Service Date: December 30, 1980

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA
****

IN THE MATTER of The Application	)
By MONTANA POWER COMPANY For Au-	) UTILITY DIVISION
thority To Establish Increased	) DOCKET NO. 80.4.2
Pates For Natural Gas and Electric	) ORDER NO. 4714a
Service In The State Of Montana	)

ERRATA SHEET

Page 33:

1. On the line "Federal Income Taxes", please substitute 1,841 for 2,343.

2. On the line "Montana Corporate License Tax", please substitute 368 for 395.

3. One the line "Sub Total", please substitute 30,196 for 30,723.

4. On the line "Total Operating Expenses", please substitute 101,140 for 101,667.

5. On the line "Utility Operating Income", please substitute 34,856 for 34,329.

6. On the line "Balance For Return", please substitute 34,862 for 34,335.

7. On the line "Rate of Return Earned", please substitute 7.87% for 7.76%.

Page 69:

1. In Finding of Fact number 131, please substitute 21,707,000 for 22,754,000.

Page 70:

1. On the line "Balance For Return", please substitute 34,862 for 34,335.

2. On the line "Return Deficiency", please substitute 10,923 for 11,450.

3. On the line "Revenue Deficiency", please substitute 21,707 for 22,754.

4. On the line "MCC Tax", please substitute 15 for 16.

5. On the line "State Tax", please substitute 1,464 for 1,535.

6. On the line "Federal Taxable Income", please substitute 9,305 for 9,753.

7. On the line "Net Operating Income", please substitute 10,923 for 11,450.

Page 87:

1. In Order No. 1, please substitute 21,707,000 for 22,754,000.

Two errors in the calculation of taxes gave rise to this errata sheet. First the calculation of state taxes was in error due to including a MCC recommendation that was not accepted. The following calculations detail the correction of the state taxes:

585,000 Recommendation by MCC (Hess)

x .0675 Montana License Tax
(39,000) Adjustment To State Taxes

(753,000)* Decrease in State Taxable Income (MCC)
(491,000)* Decrease in State Taxable Income (Commission)
262,000 Difference
x .0675 Montana License Tax
18,000 Adjustment To State Taxes

389,000 MCC State Taxes
(39,000) Less Adjustment 7
18,000 Plus Adjustment
368,000 State Taxes Approved By The Commission

Federal Taxes were in error due to adding an adjustment to taxes which should have been subtracted. The following calculations detail the correction of the Federal Taxes:

262,000 (See above - Difference)
(18,000) (See above - Adjustment Tc Stale Taxes) '~
244,000 Sub Total
x .46 Federal Income Tax
112,000 Adjustment to Federal Taxes

585,000 Adjustment By MCC (Hess)
(39,000) (See above - Less Adjustment)
546,000 Sub Total
x .46 Federal Income Tax
(251,000) Adjustment to Federal Income Taxes

1,980 Federal Taxes per MCC
112 Plus Adjustment to Federal Taxes
(251) Less Adjustment to Federal Taxes
1,841 Federal Taxes Accepted By The Commission

NOTE: These net adjustments are the correction of computational errors, they do not result from changes in issues decided in the order.

* From proforma interest calculations.

Service Date December 22, 1980

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER of the Application by MONTANA POWER COMPANY for authority to establish increased rates for natural gas and electric service in the State of Montana.	UTILITY DIVISION DOCKET NO. 80.4.2 ORDER NO. 4714a

APPEARANCES

FOR THE APPLICANT:

Mark A. Clark, Attorney at Law, 40 East Broadway, Butte, Montana, appearing on behalf of the Applicant

FOR THE PROTESTANTS:

James C . Paine, Montana Consumer Counsel, 34 West Sixth Avenue,
Helena, Montana, appearing on behalf of the consuming public of the
State of Montana

John Allen, Consumer Counsel Staff Attorney, 34 West Sixth Avenue, Helena, Montana, appearing on behalf of the consuming public of the State of Montana

FOR THE INTERVENORS:

Phyllis A. Bock, Attorney at Law, Montana Legal Services, Helena, Montana, appearing on behalf of Montana's Power to the People

James A. Robischon, Attorney at Law of the firm of Poore, McKenzie, Roth, Robischon and Robinson, PC, 1341 Harrison, Butte, Montana, appearing on behalf of the Anaconda Company

Terry A. Wallace, Attorney at Law, 119 Mount Avenue, Missoula, Montana, appearing on behalf of the Distxict XI Human Resources Council, Inc.

Anne McIntyre, Attorney at Law, 119 Mount Avenue, Missoula, Montana, appearing on behalf of the District XI Human Resources Council, Inc.

Edward C. Alexander, Attorney at Law of the firm of Alexander, Kuenning, Miller and Ugrin, P. O. Box 1744, Great Falls, Montana, appearing on behalf of the Shareholders' Committee

C. W. Leaphart, Jr., Attorney at Law of the Leaphart Law Firm, 1 North Last Chance Gulch, Helena, Montana, appearing on behalf of Champion International and Ideal Basic Industries, Inc.

William J. Weigel, Jr., Attorney at Law, 341 CSG/JA, Malmstrom AFB, Montana, appearing on behalf of the Executive Agencies of the United States

Richard F. Gallagher, Attorney at Law, 302 Northwestern Bank Building, Great Falls, Montana, appearing on behalf of the Great Falls Gas Company

Gregory B. Holt, 411 Northwestern Bank Building, Great Falls, Montana, appearing on behalf of Treasure State Pipe Line Company and Consumers Gas Company

William Current, 910 Roosevelt Highway, Shelby, Montana, appearing on behalf of the Shelby Gas Company

FOR THE COMMISSION:

Eileen E. Shore, Staff Counsel
Dan Elliott, Administrator, Utility Division
Eric Eck, C. P. A.
Karen Ostermiller,
C.P.A. Larry Finch, Economist

BEFORE:
THOMAS J. SCHNEIDER, Commissioner & Hearing Examiner
GORDON E. BOLLINGER, Chairman
CLYDE JARVIS, Commissioner
JAMES R. SHEA, Commissioner
GEORGE TURMAN, Commissioner

FINDINGS OF FACT
PART A
General

1. On April 8, 1980, the Montana Power Company (MPC, the Company or Applicant) filed with the Commission its application for authority to increase rates and charges for electric and natural gas utility service. The proposed rates are designed to produce an increase in annual gross operating revenues of $36,257,616 for electric service and $30,528,220 for natural gas service, based on a historic test year ending September, 1979, adjusted for known and measurable changes.

2. On April 17, 1980, the Commission issued a notice of prehearing conference on the application to adopt increased rates for electric and natural gas service. On May 13, 1980, pursuant to this conference held May 8, 1980, the Commission issued a procedural order.

3. The Montana Consumer Counsel (MCC) has participated in this Docket on behalf of utility customers since the inception of these proceedings .

4. On June 27, 1980, MPC filed an amendment to its original application to reflect the decline in the level of sales of natural gas to Northern Natural Gas Company. Supplemental direct testimony was filed in which this change was reflected. This decline in the level of sales to this company caused the test period gross revenues at the proposed rates to increase from $178,056,526 before the change, to $183,733,626 after the change, or an increase of $5,677,100.

5. On September 11, 1980, the Commission issued notice of public hearing on the application to adopt increased rates for electric and gas service.

6. On October 7, 8, 9 and 10, 1980, pursuant to notice of public hearing, a hearing was held in the Department of Highways Auditorium and in the House Chambers of the Capitol Building, Helena, Montana.

7. Applicant proposes September, 1979, adjusted to reflect known and measurable changes. be used as the test period in this Docket.

8. The September, 1979 test year is found by the Commission to be a reasonable period within which to measure Applicant's utility revenues, expenses and returns for the purpose of determining a fair and reasonable level of rates for electric and gas service.

9. The record in Docket No. 6720 was incorporated into this Docket

10. The electric utility rate structure has been separated from this procedure, and will be considered during Phase II of this Docket. The hearing is scheduled to commence June 30, 1981.

PART B
RATE OF RETURN
Capital Structure

11. Applicant's witness Mr. Woy presented a total utility capitalization as of December 31, 1979 including an adjustment to the common equity amounts for the sale of common stock on March 5, 1980. In past proceedings the Applicant has allocated capital between utility and nonutility operations and then among the three utility departments. Use of total utility capitalization is recommended as it is easy to compute and produces similar results.

12. Dr. Caroline M. Smith, who presented expert testimony for the Montana Consumer Counsel, used the capital structure at December 31, 1979 adjusted for the common stock issue of March, 1980. MCC developed a capital structure allocated to electric and gas operations rather than total utility capitalization presented by the Applicant. Mr. Woy, in deriving his capital structure, reduced common equity by deducting the Mystic Lake excess capital surplus and by eliminating the undistributed earnings in subsidiary investments. Dr. Smith excludes the remaining investment in subsidiaries in the amount of $9,792,000. Also, $4,529,000, representing the Company's miscellaneous investments in stocks, bonds and notes is removed from the capital structure by MCC. These two adjustments totaling $14,321,000 are removed from common stock.

13. Applicant proposes to include unamortized post-1970 investment tax credits in the capital structure. MCC witness Dr. Smith excludes these credits in her capital structure.

14. Dr. Smith reflects preferred stock in the amount of $68,984,000. Applicant in ILS capital structure uses $67,360,000. The difference of $1,624,000 is due to issuance expense. The Commission agrees with the Applicant that the most accurate reflection of securities in the capital structure includes issuance expenses. The amount of preferred stock accepted by the Commission is $67,360,000.

15. Historically, capital structure has been allocated to specific utility 3 segments. Applicant suggests the use of a total utility capital structure while MCC recommends the traditional gas and electric allocations. Based on having long evaluated the Applicant's capital structure on the basis of electric and gas operations, the Commission finds the use of capital structure

allocated to electric and gas operations to be appropriate.

16. Both Applicant and MCC agree that the $14,321,000 which Dr. Smith removed from the common stock portion of the capital structure is composed of investment in nonutility subsidiaries and miscellaneous invest meets in stocks, bonds and notes. Mr. Woy states in his rebuttal testimony:

"I do not believe, however, that it is proper to assume that our total investment in subsidiaries and nonaffiliated companies is assignable entirely to common stock equity. Since these investments are a part of the overall capital structure, I would have attributed the $14,321,000 proportionately to long-term debt, preferred stock, and common equity. " (Rebuttal Testimony, FVW-3)

No evidence in this record supports the assertion by Dr. Smith that the Applicant's investment in nonutility subsidiaries is entirely composed of common stock. The Commission finds the reduction of $14,321,000 in the capital structure properly allocated to the entire capital structure on a proportionate basis.

17. With regard to unamortized investment tax credits, the Commission for the purposes of this Docket, does not accept their inclusion in the capital structure. Since deferred taxes are not allowed in rate base it is consistent to exclude such items from the capital structure.

18. In order to obtain the most accurate capital structure, an adjustment must be made to eliminate $5,939,000 from the equity portion of the electric capital structure. This amount represents acquisition adjustments which have been removed in previous Commission orders (4220c, 4350d).

19. The Commission accepts the following capital structure for the natural gas utility:

Type of Capital	Amount	Percent of Capitalization
Long-Term Debt	$ 86,716,171	50.55
Preferred Stock	17,141,626	9.99
Common Stock	67,695,143	39.46
	$171,552,940	100.00

20. The Commission accepts the following capital structure for the electric utility:

Type of Capital	Amount	Percent of Capitalization
Long-Term Debt	$246,807,564	51.17
Preferred Stock	48,787,706	10.12
Common Stock	186,731,790	38.71
$482,327,060 100.00		

Cost of Debt

21. The cost of debt capital is not a controverted issue in this case. The cost of long-term debt is

based on the embedded cost at December 31, 1979. Since the Commission selected separate capital structures for gas and electric operations, the debt allocations proposed by Dr. Smith are accepted. The pollution control debt and gas note are directly assigned to electric and gas operations respectively. Total first mortgage and debenture debt is allocated according to rate base. The Commission finds the cost of debt for electric operations to be 8.50 percent and for gas operations to b e 8.82 percent. (CMS-1, p. 1)

Cost of Preferred Stock

22. As was the case with long-term debt, the cost of preferred stock is not a controverted issue. The cost of preferred stock is based on the embedded cost of preferred shares outstanding at December 31, 1979, and has been found to be 7.77 percent by the Applicant and MCC. This cost is acceptable to the Commission. (Direct FVW-1, SCH. 3)

Cost of Common Equity
Champion International

23. Champion International's witness Bowyer performed a discounted cash flow analysis on MPC equity. Additionally, 11 companies of similar financial characteristics were analyzed. In order to achieve comparable companies, Dr. Bowyer included firms which had the same bond ratings as MPC.

24. Dividend growth was not used in Dr. Bowyer's DCF analysis. This element, which is usually included in DCF models according to Dr. Bowyer, is subject to significant variances in the percentage of common stock earnings paid out in dividends.

25. Instead, Dr. Bowyer relied on the growth in book value per snare. These growth rates were computed for two different periods; a ten year period 1969-1979, and a five year period 1974-1979. The average growth rate in book value per share of MPC common stock for the ten year period was 4.58 percent and for the five year period 3.42 percent.

26. The second growth factor used in the DCF analysis was dividend yields. These yields were computed by dividing the dividend paid per share by a market price. Market price was computed from a 40 month period ended April 30, 1980. The dividend yield was the average of dividends per share for the years 1977 through 1980. The market dividend yield for MPC is 8.39 percent. A five percent allowance for market pressure and issuance costs results in a dividend yield of 8.83 percent.

27. The Cost of common equity is the sum of the book value per share growth rate and a dividend yield. results of the DCF analysis indicate the cost of common equity for MPC falls in a range of from 12.25 percent to

13.91 percent. In the opinion of Dr. Bowyer, 12.5 percent is the cost of common equity for MPC.

28. Dr. Bowyer used 11 comparison companies in his presentation. This number of companies is not large enough to give a clear indication of the correct equity return in this Docket. The Commission has consistently denied recommendations based upon small groups of comparison companies due to the risk that the result will be biased by factors unique to those firms. For the reasons noted above, the Commission rejects the return on common equity recommended by Champion.

Common Shareholders

29. The Common Shareholders' witnesses O'Leary and Jeffries use the following methodologies in arriving at a return on equity of 17.1 percent:

(a) A market-based approach was used to analyze investors' expectations. The rate of return on common equity equals the dividend yield plus market price appreciation resulting from growth in common stock book value, earnings and dividends.
(1) The dividend yield was calculated by dividing the dividend by the stock price. The average of the monthly high and low common stock market prices since October, 1979 were used. The average market price for Applicant's common equity was $20. 91 during the eight months ended May, 1980. The common stock dividend is $2.12 per share, r exulting in an average yield of 10.1 percent.
(2) Analysis of Applicant's experienced growth in common stock book value, earnings per share and dividends was performed to determine the growth factor. The outlook for other electric utilities was also reviewed using Value Line Investment Survey. A future growth rate of 5.5 percent was estimated to be reasonable for the Applicant.
(3) The rate of return on common equity was determined to be 15.6 percent. This rate of return was then adjusted for market pressure, market variation, and the cost of selling new common stock. Based upon these studies, the Common Shareholders recommend a return on common equity of at least 17 percent.
(b) The returns earned on common equity by nonregulated companies listed in Standard & Poor's 400 Industrials were examined . For 1979 the return on common equity for the nonregulated companies was 17.1 percent. Witness Jeffries concludes that the market data shows that investors perceive the Applicant to have greater investment risk than the average industrial company, therefore, a fair rate of return for the Applicant should be higher than the 17.1 percent return earned on common equity by the industrials in 1979.

30. The Commission does not accept the return on equity of 17.1 percent proposed by the Intervening Common Shareholders for the following reasons:
(a) In arriving at a recommended return on equity of 17.1 percent, the Intervening Common Shareholders considered the equity returns of nonregulated companies included in Standard & Poor's 400 Industrials as alternative investments to the Applicant. (Jeffries' Direct, p. 12) Although the Applicant must compete with other utility and nonutility companies for capital, a direct

comparison cannot be drawn between returns earned on common equity by the Applicant and returns earned by nonregulated companies. Many factors vary between the Applicant, a regulated utility, and the nonregulated Standard & Poor's 400 Industrials. Regulatory agencies provide utilities the opportunity to earn an approved rate of return; whereas the return earned by unregulated companies is controlled by the companies' management. Also, when using a broad index such as Standard & Poor's 400 Industrials, consideration must be given to the fact that some companies included in the index have a much higher risk than utility companies. Therefore, the returns earned by these high risk companies will be much higher in comparison to utility companies, and will tend to make the average return figures for the unregulated companies included in the index higher than if these high risk companies were excluded from the study. Finally, unregulated companies prices are subject to competition, a factor which may prevent price increases to keep up with inflation, whereas regulated utility companies can request and be granted rate increases from regulatory agencies. These factors must be considered if a fair comparison is to be drawn.

(b) The Intervening Shareholders recommend a 15 percent price adjustment for the cost of selling new common stock, for market pressure, and for normal market variation . The Shareholders state this is justified, however they offer no quantification of how they arrived at the 15 percent figure. (Jeffries' Direct, p. 17) Also, the Commission's accepted rate of return figure does not include an allowance for issuance costs or market pressure, as sufficient evidence was not provided in this case to justify the necessity of such an adjustment. There was no indication that new issuances will occur in the near future.

Montana Power Company

31. Applicant uses the following methodologies in arriving at a return on equity of 15 percent:

(a) Applicant's witness Eugene W. Meyer described the capital markets in which the Applicant must operate in order to attract the necessary capital to provide the required service to its customers. The markets are reflective of the Nation's difficult economic conditions, i.e. high interest and inflation rates, thus creating pressures on the Applicant's ability to raise capital to meet the energy requirements of its service area.

(b) Witness Meyer calculates that a 15.3 percent return on common equity will produce a 20 percent market price premium on Applicant's common stock. It is the opinion of Mr. Meyer that a return of at least 15.3 percent must be earned over time in order to protect existing shareholders from suffering any economic confiscation if new common equity is issued.

According to Mr. Meyer, a 15 percent return on common equity as requested by the Applicant is deemed to be adequate over the long-term.

(c) Applicant's witness Dr. Charles F. Phillips selected the comparable earnings method to determine the cost of equity. This is an alternative investment approach that focuses on what capital can earn in various alternatives with comparable risks. This method involves examining earnings on book common equity for enterprises that have comparable risks or by examining earnings on book common equity for enterprises that have different risks and then making an allowance for these risk differences. Two groups of companies are used in the comparable earnings method, Standard Poor's 400 Industrials and Moody's 24 Utilities. Results of the study are:

(1) Industrial earnings increased from 10.4 percent to 14.8 percent from 1970 to 1974. However, due to the recession, industrial earnings decreased in 1975 to 12.4 percent, but rose to 14.5 percent in 1976 and to 15.2 percent in 1978. (Direct, p. CFP-41)

(2) The rate of return earned on average common equity for Moody's 24 Utilities declined from 11.1 percent in 1970 to 10.4 percent in 1975, rose to 11.1 percent in 1977, and declined to 10.8 percent in 1978.

Dr. Phillips concludes that these results indicate that the risk of public utilities has increased relative to the risk of industrial enterprises in recent years.

(3) Dr. Phillips' study of price-earnings ratios indicates that until 1967 the utilities were competitive with the industrial enterprises. Since that time, the utilities' ratio has consistently been below the industrials' ratio. This indicates that investors are willing to pay less for each dollar of earnings generated by utilities as opposed to industrials.

(4) Dr. Phillips' study of market price-book equity ratios again indicates that until 1967 the utilities were competitive with the industrials. Since that time, the utilities' ratio has been consistently below the industrials' ratio. Moody's 24 Utilities have not sold above book value since 1973. This means investors do not value a dollar of net book assets of utilities as highly as those of industrials. (Direct, p. CFP-44) Investors have, according to Dr. Phillips, reappraised upward the financial risk of utilities, including the Applicant, as they believe that industrials are able to make a better adjustment to the current economic conditions than are utilities, i. e., the utilities' financial risk is about the same as, or slightly higher than the financial risk of the average industrial company.

(d) Dr. Phillips concludes that the cost of common equity for the Applicant falls in a range from 15 percent to 15.5 percent.

32. The Commission does not accept the return on equity of 15 percent proposed by the Applicant for the following reasons:

(a) Witness Meyer states that Applicant's common stock must sell at 20 percent over book value in order to protect existing shareholders from suffering any economic detriment if new common equity is issued. Mr. Meyer says this 20 percent premium would protect the shareholders against the worst possible market conditions. Rate making should reflect average, not worst, market conditions. Rate making is not intended to make utility operations riskless. The burden for protecting the Applicant's shareholders against the worst market conditions cannot be justly placed on the Applicant's ratepayers.

(b) Witness Phillips makes several comparisons between industrial and utility companies, utilizing Standard & Poor's 400 Industrials and Moody's 24 Utilities. Direct comparisons regarding earnings and various ratios cannot be drawn between these two groups of companies due to the many factors which differ between unregulated industrials and regulated utility companies.

Montana Consumer Counsel

33. MCC witness Dr. Caroline Smith uses the following methodologies in arriving at a return on common equity of 13 .45 percent for electric utility, and 13.60 percent for gas utility:

(a) Application of the discounted cash flow (DCF) techniques to

Applicant's financial data. The DCF approach is an analytical method which focuses on stock market conditions in order to arrive at the rate of return which is required by investors in the marketplace.

1. Dividend yield was estimated at 9.60 percent through the use of current price and dividend data applicable to the ninety-six electric and combination electric and gas utilities which are traded on the New York Stock Exchange. (Exh. MCC-F, p. 24)

2. The future dividend growth rate was estimated at 3.23 percent, derived by considering Montana Power Company's historical weighted average growth of 2.83 percent, the industry weighted average growth of 3.34 percent, and Montana Power Company's dividend yield of 9.60 percent. The growth expectation for Montana Power Company's dividends in the long-term future is 12.83 percent, as determined by the DCF model. Data applicable to the ninety-six electric and combination electric and gas utilities referred to above was used to produce the industry-wide growth estimates. (Exh. MCC-G, CMS-7)

(b) Analysis of the rate of return earned on common equity capital in recent years by regulated electric and combination utility companies as well as firms in the unregulated sector. The results were as follows:

1. Regulated utilities have experienced average earnings on common equity in the range of 11. 0-12.7 percent over thc 1970-78 period;

2. Gas distribution companies have earned in the range of 10.6-12.6 percent; and

3. Telephone utility companies have earned in the range of 9.1-13.8 percent.

(c) Analysis of Beta coefficients which are used to measure risk, indicate, on a percentage basis, the extent to which an individual common stock rises and falls with the market. It was determined that on the average, the electric utility industry as a whole has a low average Beta. The range for electric and combination utilities traded on the New York Stock Exchange is .50-.85, with an industry average of .63. Montana Power Company's Beta is .75. (9n the average, it was found that electric utility common stock is less volatile than the stock market as a whole.

(d) An allowance of no more than 10 basis points (.10) to the equity cost rate for public stock issuance costs is recommended.

34. The Commission accepts the methodology sponsored by MCC as fundamentally sound. MCC relies on a discounted cash flow (D5F) analysis, and an analysis of the rate of return earned on common equity capital by regulated electric and combination utility companies as well as firms in the unregulated sector.

MCC witness Smith used the ninety-six electric and combination electric and gas utility companies which are traded on the New York Stock Exchange to produce industry-wide estimates of yield and growth. These companies I provide an appropriate frame of reference for evaluating investors' perceptions of the financial prospects for the Applicant. (Exh. MCC-F, p. 24)

The current dividend yield for each company was determined by dividing the current annual dividend by the stock's market price. The dividend user? as that published in the March, 1979 issue of Standard & Poor's Stock Guide. The market price used was the average of the high and low prices for the six months from September through February, 1979. Witness Smith believes the high level of interest rates was an abnormal situation, and that the pre-Three Mile Island period is most normal with respect to estimating electric and combination utility costs Consequently, she used price and growth data as of the end of 1978 and beginning of 1979 to determine the cost of common equity to the Applicant. The average dividend yield for the ninety-six companies was found to be 9.46 percent. (Exh . MCC - F, p . 24)

The expected rate of dividend growth was determined by analyzing growth rates in dividends, earnings and book value per share of common stock for the ninety-six companies in t},e study. Ten different time periods were used, one year, two years, and so on, up to ten years. Most of the :t growth rates were found to cluster in the 2.5 to 3.5 percent range. The weighted average of the growth rates was 3.34 percent. (Exh. NICC-F, p.27)

The results of these studies indicate that investors currently require a return on common equity capital of approximately 12.8 percent.

Witness Smith then applies a mathematical model which she constructed to calculate the market cost of equity capital to the Applicant. This model accounts for and quantifies differences in the market cost of common equity between the companies. Results of applying this model indicate that investors perceive the Applicant to be a slightly higher risk than the industry as a whole. Specifically, investors require a return of about one-tenth of a percentage point above the industry average equity of 12.8 percent, resulting in an estimated cost of common equity capital for the Applicant of 12.88 percent.

Witness Smith recommends the current cost of equity capital applicable to the Applicant's utility operations is in the range of 13.25 to 13.75 1 percent. This includes the cost of equity estimate immediately prior to the Three Mile Island incident, and also includes about a 65 basis point addition to account for the changes in the cost of money that have occurred since that time. (Tr. 4(a), p. 692)

Within MCC's recommended range, the Commission finds 13.45 percent to be the appropriate rate of return on common equity capital for the Applicant's electric and gas utility operations. The Commission has adopted deferred accounting techniques and gas tracking procedures, therefore a risk differential between Applicant's electric and gas utility is not appropriate .

Rate of Return

35. Based on the findings for long-term debt, preferred stock and common equity, the following capital structure and costs are determined to be appropriate:

Electric

Type Structure	Capital	Cost	Weighted Cost

Long-Term Debt	51.17%	8.50%	4.349%
Preferred Stock	10.12	7.77	.786
Common Equity	38.71	13.45	5.207
	100.00%		10.342%
Gas			
Long-Term Debt	50.55%	8.82%	4.458%
Preferred Stock	9.99	7.77	.776
Common Equity	39.46	13.45	5.307
	100.00%		10.541%

PART C
RATE BASE
Electric Utility Rate Base

36. The following schedule sets forth the electric utility rate base, with the final figure of $442,706,311 representing the electric rate base approved by the Commission.

Test Period - 13 Month Average

	13 Month Average 9/30/79 Adjusted for Known Changes
Utility Plant in Service	
Electric	$554,322,927
Common	11,959,491
Subtotal	$566,282,418
Milwaukee Line	3,262 402
Total Utility Plant In Service	$569,544 82
Accumulated Depreciation	
Electric	$101,127,268
Common	2,106 234
Subtotal	$103,233 502
Milwaukee Line	231,085
Total Accumulated Depreciation	$103,464 587
TOTAL NET PLANT	$466,080,233
Eliminate Amounts Recorded on Books in Excess of Original Cost-Mystic Lake	$ (1,883,582)
LESS: Customer Contributed Capital	
Accumulated Deferred Income Taxes	
Amortization of Plant Acquisition Adjustment	$ 105,194
Accelerated Amortization	1,816,954
Liberalized Depreciation	29,775,539
Accumulated Deferred investment Tax Credits (Pre 1971)	1,340,566
Customer Advances for Construction	1,120,638
TOTAL CUSTOMER CONTRIBUTED CAPITAL	$ 34,158,891
PLUS: Working Capital	
Gross Cash Requirements	$ 6,979,821
Credit for Accrued Taxes	(5,457,809)
Fuel	1,544,915
Materials Supplies	5,862,088
A/C 136 Other Deferred Debits	
Kerr Rental Settlements	$ 7,390,443
Accumulated Deferred Income Taxes	

A/C 283 Other Amortization - Kerr Rental Settlements	(3,996,657)
Net Kerr Rentals	$ 3,393 786
TOTAL WORKING CAPITAL	$ 12,329,801
Applicant's Adjusted Total Electric Utility Rate Base	$442,360,561
MCC's Adjustment for Excess Accumulated Deferred Taxes	345,750
Commission Adopted Tota] Electric Utility Rate Base	$442,706,311

37. The adjustments to electric rate base proposed by the Applicant are not contested for purposes of this case. Both MCC and the Commission accept the Applicant's adjustments to electric rate base. The Commission accepts one further adjustment to electric rate base proposed by MCC, which has the effect of increasing electric utility rate base.

MCC witness George E. Hess proposes an adjustment to the Applicant's adjusted total electric utility rate base to reflect the amortization of excess accumulated deferred income taxes. The accumulated deferred income tax account is excessive, as it contains a surplus of dollars that were collected at the old corporate income tax rate of 48 percent, and which are unnecessary to meet tax obligations at the current 46 percent tax rate. $1,383,000 was identified as the amount accumulated in excess of the current 46 percent tax rate. Mr. Hess proposes to amortize this amount over a five-year period, however the Commission accepts MCC witness John W. Wilson's proposal to amortize this amount over a two-year period. The two-year period will allow the overcollected revenues to be returned to ratepayers as soon as possible, thereby minimizing the difference between those ratepayers who actually provided the dollars and those who will receive the benefit of rates which reflect the adjustment. (Exh. MOUTH, p. 26)

The adjustment, accepted by the Commission, $345,750, represents one-half of the amount of excess accumulated deferred taxes to be amortized each year for a period of two years. This adjustment is consistent with the methodology sponsored by Mr. Hess. If the amortization of excess accumulated deferred taxes had begun in the test year, average accumulated deferred taxes deducted from rate base would be reduced by one-half the annual amortization. (Exh. MCC-D, p. 22)

Gas Utility

38. MPC presented a 13 month average rate base ended September 30, 1979, adjusted for known changes. The gas rate base presented by the Applicant with adjustments is as follows:

Test Period - 13 Month Average

	13 Month Average 9/30/79 Adjusted for Known Changes
Utility Plant in Service	
Gas	$180,181,011
Total Utility Plant In Service	8,637,180
Accumulated Depreciation & Depletion:	
Gas	$ 66,458,710
Total Accumulated Depreciation & Depletion	$ 67 977 664
TOTAL NET PLANT	$120,840,527
Gas Stored Underground	$ 17,152,633
Plant Held for Future Use	$ 2,428,412
LESS: Customer Contributed Capital:	
Accumulated Deferred Income Taxes-Liberalized Depreciation	
Accumulated Deferred Investment Tax Credits	$ 3,823,820
(Pre 1971)	429,658
Customer Advances for Construction	861,112
Accumulated Deferred Income Taxes - Amortization of Certain Purchased Natural Gas Properties	2,132,232
TOTAL CUSTOMER CONTRIBUTED CAPITAL	$ 7,246,822
PLUS: Working Capital	
Gross Cash Requirements	$ 3,927,469
Credit for Accrued Taxes	(1,519,336)
Prepayments	9,075,762
Anaconda Co. Billing Deficiency	(1,738,918)
Materials and Supplies	1,990,499
T0TAL WORKING CAPITAL	$ 9,735,476
Applicant's Adjusted Total Gas Utility Rate Base	$142,910,226
MCC's Adjustment for Excess Accumulated Deferred Taxes	33,250
Commission Adopted Total Gas Utility Rate Base	$142,943,476

39. MCC proposed two adjustments which, if adopted, would increase the rate base presented by the Applicant. The adjustments by Mr. Hess represent one-half of his adjustment to amortize excess accumulated deferred taxes plus one-half of the adjustment he made to defer current taxes on deferred income. The second adjustment to rate base is not accepted at this time for the reasons noted in the section which discusses full tax normalization .

40. As was noted in the electric rate base section, Mr. Hess proposes an adjustment which reflects the five year amortization of excess accumulated deferred income taxes. A two year amortization of this excess is accepted by the Commission . $133,000 was identified as the amount accumulated in excess of the current 46 percent tax rate.

41. The adjustment accepted by the Commission, $33,250, represents one-half of the amount of excess accumulated deferred taxes to be amortized each year for a period of two years. If the amortization of excess accumulated deferred taxes had begun in the test year, average accumulated deferred taxes deducted from rate base would be reduced by one-half the annual

amortization. (Exh. MCC-D, p. 22)

42. The addition of $33,250, results in a total gas utility rate base accepted by the Commission of $142,943,476.

PART D
COST OF SERVICE
Pro Forma Interest Expense

43. The same methodology was utilized to calculate the Applicant's interest expense, the adjustment sponsored by MCC, and the adjustment accepted by the Commission The weighted debt cost was multiplied by the sum of rate base plus average construction work in progress to perform the calculation. MCC obtained a different result than the Applicant because MCC used its adjusted rate base figure and the weighted debt cost included in its rate of return calculation. The Commission accepted a different result than either the Applicant or MCC obtained, as the Commission used the accepted rate base figure and the accepted weighted debt cost in the calculation of interest expense and the resulting income tax adjustments. The total interest expense for electric utility is calculated by the Commission to be $20,934,000. The resulting adjustment to federal income taxes is a decrease of $211,000, and the resulting adjustment to Montana Corporate license tax is a decrease of $33,000. The total interest expense for gas utility is calculated by the Commission to be $6,555,000. The resulting adjustment to federal income taxes is a decrease of $131,000, and the resulting adjustment to Montana corporate license tax is $21,000.

Capitalized Interest

44. Mr. Hess in his testimony refers to the testimony of Mr. Woy where the Applicant proposes to use deferred tax accounting for interest capitalized. (Direct, p. 14) MCC does not feel that deferral of capitalized interest results in a proper matching of revenues and expenses. Citing the effects of inflation and growth on construction costs, Mr. Hess testified that tax reductions will steadily increase.

45. Mr. Woy proposes to defer these tax reductions during the period of construction, and flow them back to the customer when the plant comes into service. The deferrals would reduce rate base and the amortization would reduce cost of service over the life of the plant. (Direct, p. 22)

46. Given the construction program of the Applicant in the recent past (Colstrip Units 1, 2, 3, and 4) and planned construction in the future (Resource 89), there is no reason to defer recognition of the tax savings associated with capitalized interest. The chance that future ratepayers will have to pay higher taxes due to the current deduction of capitalized interest is slight. The reduction of $748,000 from electric utility expenses and $78,000 for gas is accepted by the Commission. The deferral of capitalized interest is rejected.

Amortization of Excess Balance

47. Before 1979 the federal corporation income tax rate was 48 percent. That rate became 46

percent as of January, 1979. MCC presented testimony by Mr. Hess and Dr. Wilson which recommended a reduction of the existing deferred tax reserve.

48. Dr. Wilson points out in his testimony that while deferred taxes have been accrued in the past at 48 percent, the current taxes will not exceed 46 percent. A two year period to amortize the refunds of the excess balance to customers is recommended by Dr. Wilson. In addition, Dr. Wilson noted that since taxable income would decrease as a result of the refund, additional revenues should be refunded.

49. Mr. Hess urges the Commission to amortize the excess deferred tax reserve over a five year period. The amount of excess taxes identified by Mr. Hess was $1,383,000 for electric operations and $133,000 for the gas utility .

50. Mr. Kolbe, who testified on behalf of the Applicant, is of the opinion that this adjustment violates Treasury Regulations Section 1.167(1) 1(h)(2)(i). According to Mr. Kolbe the most reasonable interpretation of this section is that the deferred tax reserve is reduced in any taxable year by reference to the tax rates applicable in such taxable year, regardless of whether such rates are higher or lower than the rates in effect for the year when the reserve was created. (Rebuttal KWK, pp. 9-10)

51. The Commission has considered the excess balance situation in a prior Docket (No. 6701). In that proceeding the Commission ordered an amortization of the excess balance over a two year period. The defense raised by the Applicant is that by returning the excess balance to the ratepayers, the use of accelerated depreciation will be lost. The change in the tax rates means that the accrual for deferred taxes is too large and must be reduced. The Commission accepts the amortization of $1,383,000 for electric operations and $133,000 for gas over a two-year period. The two year proposal is seen as the best way to minimize the difference between the ratepayers who provided the dollars and those who will receive the refund.

For the purposes of this Docket, the proper reduction to operating expenses is a ($692,000) for amortization of excess balance in electric operations. The adjustment in the gas utility is ($67,000).

Full Normalization

52. MCC witnesses Hess and Wilson presented testimony and exhibits on the subject of complete normalization of deferred taxes. Traditional 4 utility regulation has allowed deferred taxes as a current expense for rate making purposes. Deferred taxes arise as a result of the use of accelerated depreciation for tax purposes an straight-line depreciation for expense and rate base purposes. MCC argues that this method causes ratepayers to pay for deferred taxes which are not paid currently. In addition, ratepayers are asked to pay the current tax expenses associated with creation of the deferred tax reserve.

53. A new method of accounting for deferred taxes known as full normalization is being introduced in this Docket. Full normalization is designed to defer both the benefits and the costs of building a deferred tax reserve to the same future period.

54. Dr. Wilson describes full normalization in his direct testimony:
Full normalization with respect to deferred taxes consists of adjustments to tax expenses for ratemaking purposes so that those deferred taxes which are not paid currently are reflected as if they were a current expense on the income statement and as an addition to the deferred tax reserve on the balance sheet. Also, taxes currently attributable to the taxable income from which the deferred tax reserve addition was obtained are deducted from current revenue on the income statement and a corresponding non-cash income allowance for taxes on deferred credits (AFTDC) is recorded as a deferred charge on the balance sheet. (Direct, pp. 13-14)

55. When a deferred tax credit reserve is funded, the reserve is accepted as a ratemaking expense. Since the deferred taxes are not a current expense, they are not a deductible expense for income tax purposes.

56. Dr. Wilson supports Mr. Hess' proposed adjustment to the Company's cost of service which defers the current tax costs associated with the provision for deferred tax benefits to those future periods when future ratepayers will ultimately benefit from the availability of dollars accumulated in the deferred tax account. (Direct, p. 20)

57. As ratepayers benefit from the deduction of accumulated deferred taxes from rate base for ratemaking purposes, Dr. Wilson feels that it would be consistent to make a rate base addition for the accumulated deferred tax charges.

58. To achieve full normalization, Dr. Wilson recommends a decrease in depreciation expense to recognize that portion of plant that was purchased with customer contributed deferred tax dollars. The Commission has consistently required that deferred taxes be removed from rate base to avoid an unreasonable burden on ratepayers. The depreciation adjustment proposed by Dr. Wilson errs by placing an unreasonable burden on the company. The depreciation adjustment proposed by Dr. Wilson is rejected by the Commission.

59. Mr. Hess also presented a recommendation based upon full normalization of deferred taxes. MCC Exh. D GFH-3 shows the result of present and proposed normalization of deferred taxes in terms of a single asset. Mr. Hess concluded that the revenues required to reflect income tax normalization give rise to further book/tax timing differences that are ignored in the incomplete tax normalization used by the Applicant. Both Hess and Wilson advocate full normalization as a more appropriate matching of costs and benefits.

60. Mr. Hess indicated that caution should be exercised in making this adjustment:

I would not recommend an adjustment that would jeopardize the availability of liberalized depreciation to the company. Therefore, I suggest that the Commission make this adjustment conditioned on receiving a ruling from the IRS that the adjustment does not disqualify the utility for continua use of liberalized depreciation. (Direct, p. 21)

61. The reductions in operating expense proposed by Mr. Hess for current taxes on deferred income were $2,274,000 for electric operations and $509, 030 for gas .

62. Mr. Kolbe, an expert witness for the Applicant, presented testimony in opposition to the recommendations made by Hess and Wilson. In Mr. Kolbe's view the full normalization adjustment proposed by MCC is prohibited by Treasury Regulations. The sections which apply to this situation are 1.167(1)-1(h)(1)(i)(b) and 1.167(1)-1(h)(a)(i). Possible consequences of adopting full normalization are mentioned in Mr. Kolbe's testimony:

The only permitted reductions to the reserve accounts are amounts which reflect the amount for any taxable year by which federal income taxes are greater by reason of the pr for use of accelerated depreciation and adjustments to reflect asset retirements or the expiration of depreciable lives. Any other adjustment which has the effect of reducing the amount allocable to deferred tax under Code Section 167(1) would violate this regulation. Consequently, the taxpayer would no longer be treated as using a normalization method of accounting. The ultimate result would be that accelerated depreciation could not be deducted for federal income tax purposes. (Rebuttal, KWK-6)

63. Mr. Pederson who presented testimony on behalf of the Applicant, agreed with Mr. Kolbe that full normalization would constitute a violation of treasury regulations.

64. After examining the recommendations made by all parties relating to full normalization the Commission remains uncertain as to the effect of the adjustment in terms of Treasury Regulations. During cross-examination Mr. Hess indicated that he could not assure either the Company or the Commission that the post-revenue ruling adjustment would immunize the Company from the loss of the tax dollars. (Tr. p. 686) The Commission supports the concept of full normalization as a way to better match the costs with the benefits associated with deferred taxes. Before such an adjustment will be authorized by the Commission, the uncertainty surrounding the use of accelerated depreciation must be resolved. The logical way to remove the uncertainty is to request a revenue ruling from the IRS. The Commission directs the Applicant to seek a ruling on this matter within three months from the service date of the order. If a favorable ruling is received on the use of full normalization, the adjustment proposed by Mr. Hess will be accepted and the revenues associated with full normalization will be refunded to the customers with interest at the rate of 10 percent. Should no revenue ruling be received from the IRS within two years from the service date of this order the Commission will give serious consideration in the adoption of full normalization without a revenue ruling.

Revenues & Expenses

Electric Utility

The following income and expense proposals were submitted. The final column contains the revenue and expense amounts approved by the Commission:

9/30/79 TEST YEAR

(000)

	Applicant's Revenues & Expenses	Consumer Counsel Adjustments	Consumer Counsel Revenues & Expenses	Approved Revenues & Expenses
Gross Revenues	$134,177	$ 1,819 (A)	$135,996	$135,996
i Cost of Service Purchased Power	10,017	(2,439) (B)	7,578	8,163
Steam Operation Fuel Cost	18,545	(1,037) (C)	17,508	
	17,508			
Steam Operation (Excl. Fuel Cost)	4,120	--	4,120	4,120
Steam Maintenance	6,704	--	6,704	6,704
Hydro-Operation	5,758	--	5,758	5,758
Hydro-Maintenance	1,057	--	1,057	1,057
Total Production	$ 46,200	$ (3,476)	42,725	$ 3,310
Transmission-Operation	1,879	--	1,879	1,879
Transmission-Maintenance	1,202	--	1,202	1,202
Distribution-Operation	3,935	--	3,935	3,935
Distribution-Maintenance	3,475	--	3,475	3,475
Customer Accounts Expense	3,128	--	3,128	3,128
Customer Service & Information Expense	683	--	683	683
Sales Expense	135	--	135	135
Administrative & General Expense	10,170	--	10,170	10,170
Labor Adjustment	2,778	--	2,778	2,778
Clearing Accounts Adjustment	180	--	180	180
Automotive Expense Adjustment	69	--	69	69
Sub Total	$ 73,835	$ (3,476)	$ 70,359	$70,944

	Applicant's Revenues & Expenses	Consumer Counsel Adjustments	Consumer Counsel Revenues & Expenses	Approved & Revenues & Expenses
Depreciation	12,453	--	12,454	12,241 (1)

Amortization of Common Utility Plant	76	--	76	76
Amortization of Plant Acquisition Adjustment	297	--	297	297
Amortization of Investment Tax Cr-Dr	75	--	75	75
Amortization of Investment Tax Cr-Cr	(445)	--	(445)	(445)
Deferred Income Tax:				
Liberalized Depreciation	4,943	--	4,943	4,943
Kerr Rentals (1978)	(240)	--	(240)	(240)
Kerr Rentals (1972)	(516)	--	(516)	(516)
Interest Capitalized	748	(748)(D)		
Plant Acquisition Adjustment	137	--	137	137
Montana Corporate License Tax	317	--	317	317
Taxes On Income Deferred in Prior Years	(77)	--	(77)	(77)
Amortization of Excess Balance	--	(277)(E)	(277)	(77)
Taxes Other Than Income Taxes	11,871	--	1,871	11,871
Federal Income Taxes	32	1,948 (F)	1,980	2,343
Montana Corporate License Tax	83	306 (G)	389	395
Current Tax on Deferred Income	--	(2,274)	(2,274)	--
Total Operating Expenses	$ 103,590	$ (4,521)	$ 99,069	$101,667
Utility Operating Income	$ 30,587	$ 6,340	$ 36,927	$ 34,329
Amortization of Profit on Debt Reacquired at a Discount	6	--	6	6
Balance for Return	$ 30,593	$ 6,340	$ 36,933	$ 34,335
Electric Utility Rate Base	$ 442,644		$443,637	$442,706
Rate of Return Earned	6.92%		8.33%	7.76

(A) MCC witness George Hess proposed two adjustments to electric operating revenues. First, Mr. Hess proposes to adjust the amount of secondary energy that would be purchased from the Bonneville Power Administration (BPA) under median steam flows. The Applicant estimated the BPA surplus available for secondary sales from data contained in the 1978-79 operating program for the Northwest Power Pool. Applicant calculated total BPA surplus by subtracting BPA's total system firm load and firm transfers to other utilities from the average resources used under median stream flows. A portion of the total estimated BPA surplus was then allocated to the Applicant in proportion to its share of the energy available to the Intercompany Pool (ICP). However, in the operating program, BPA's average resources used under median water conditions exclude firm transfers. Consequently, the Applicant's calculations overlook firm transfers to BPA from the California utilities and from the Central Valley Project. Including the firm transfers to BPA in the Applicant's calculations increases the secondary energy available to the Applicant by 47, 616 Mwh. The additional energy Mr. Hess estimates to be available from BPA during the test year would be resold as secondary energy to out-of-state utilities. The additional revenues resulting from these secondary sales was calculated to be $762,000. (Exh. MCC-D, pp. 4-6) The Commission accepts this adjustment, as the Applicant's calculations were understated by the firm transfers to BPA from the California utilities and from the Central Valley Project.

Second, Mr. Hess proposes an allowance for the revenue deficiency associated with REA nonjurisdictional sales. The allocated cost of service studies submitted by the Applicant show that the test year rate of return earned from REA sales is far below the rate of return it is seeking from Montana jurisdictional sales. An adjustment to revenues is made to avoid burdening jurisdictional customers with the revenue deficiency associated with nonjurisdictional sales The revenue deficiency associated with nonjurisdictional sales was calculated to be $1,057,000. (Exh. MCC-D, p. 7) The Commission adopted a similar adjustment in the Applicant's last electric rate case, Docket No. 6454, and the Commission accepts this adjustment in the current case.

(B) MCC witness George Hess proposed two adjustments to purchased power expenses in his prefiled testimony (Exh. MCC-D, pp. 8-10), and a third in his direct testimony. First, Mr. Hess adjusted Purchase Power Expense to correspond with the adjustment he made in (A) above to increase the amount of secondary revenues resulting from the increase in estimated secondary energy purchases from BPA. This additional energy was priced at the BPA secondary rates derived and used by the Applicant. (Exh. MCC-D, p . 8) The Commission accepts this adjustment, as it accepted the corresponding adjustment to the secondary energy purchases in (A) above.

The Applicant does not protest this adjustment. (D.B. Gregg, Rebuttal, p.3)

Second, Mr. Hess makes an adjustment to reflect the impact that a new purchase of power from Washington Public Power Supply System (WPPSS) will have on the Applicant's average power supply cost. The Applicant did adjust most test year costs for increases expected to occur prior to September 30, 1980. However, it failed to adjust for the purchase of power and energy from WPPSS No. 1 nuclear unit beginning in July, 1980 which will have a significant effect on the Applicant's average power supply costs. Mr. Hess calculates that the WPPSS No. 1 purchase will lower the Applicant's average cost of power supply from an average of $11.45 per Mwh to $11.08, and based on test year generation and purchases, a reduction of $0.37 per Mwh results in a reduction of $2,718,000 in average power supply costs. (Exh. MCC-D, pp. 9-10) The Commission accepts this adjustment, as it is appropriate to reflect the lower cost of power and energy from the WPPSS - No. 1 nuclear unit which was made available to the Applicant beginning July

1, 1980 due to the significant impact this purchase has on the Applicant's average power supply costs.

The third adjustment proposed by Mr. Hess results from the consideration of the WPPSS No. 1 contract effective July 1, 1980 referred to above. MCC and the Applicant agree in principle that if the WPPSS No. 1 contract is to be considered, then to be consistent two contracts, which by their terms, expire on July 1, 1980, must also be reflected. One contract involves a decrease in the firm purchase from BPA, and the other is a termination of the Hanford debt service agreement. (Tr. 4(a), p. 6723 However, MCC does not agree with the methodology used by the Applicant in costing the peak purchase from BPA. The Applicant uses the new F-7 rate - schedule in pricing peak purchases from BPA. This tariff applies a surcharge to all hours of take over six hours. The Applicant, in pricing its peak purchase, assumed that it would be incurring the maximum penalty rate each month. However, Applicant's recent purchase experiences under the F-7 rate schedule does not reflect the incurrence of the surcharge penalty, and there is no indication that the Applicant will be incurring the surcharge penalty. Therefore, Mr. Hess costs the peak purchase at $1.57 per Kilowatt per month charge, not the $3.69 surcharge penalty rate. This would increase the purchase power expense by $585,000. (Tr. 4(a), pp. 472-476) The Commission accepts the adjustment sponsored by MCC. The Applicant has not incurred the surcharge penalty rate of $3.69 per kilowatt per month charge for take over six hours, and there is no indication that the Applicant will incur the surcharge penalty. Therefore, the Commission accepts that the peak purchase should be priced at a $1. 57 per kilowatt per month charge.

(C) MCC witness George Hess proposes an adjustment to Steam Operation Fuel costs to eliminate a nonrecurring charge to test year expenses for coal inventory lost at the Corette generating station in the amount of $136,000. The Applicant agreed in its response to PSC/MCC data request 23 that this adjustment is appropriate. (Exh. MCC-D, p. 13) Therefore, the Commission accepts this adjustment.

The Commission has before it two methodologies used by ratemaking bodies to monitor the expense allowed for ratemaking purposes for coal a utility buys from its wholly owned subsidiary. At issue are coal purchases for the Company's Corette plant and for Colstrip Units #1 and #2.

The "transfer price" method is sponsored by the Montana Power Company through its witness John J. Burke. According to this method, the regulatory commission's approach is "to monitor directly tier: transfer prices charged by checking them against market-generated prices of coal." (JJB 3, p. 11) Using this method Burke claims that the prices paid by the Company to Western Energy are reasonable.

The "rate of return" method is sponsored by the Montana Consumer Counsel's witness John W. Wilson. According to this method, a regulatory commission must determine not only that "prices paid by utilities to their affiliates be reasonable by comparison to market prices, but also that the rate of profit must be independently scrutinized. " (Exh. H. p. 34, citing 3 Smith v. Ill. Bell Telephone Co., 288 U.S. 133, 152-153 (1930).) Using this method, Wilson concluded that Western Energy makes excessive profits from its sales to the company and recommends a reduction in revenue to eliminate the excess from the Company's request.

In support of his conclusion, Burke makes the following points:

a. "The Company's policy is to purchase coal from the supplier offering a reliable source of fuel at the least cost, regardless of affiliation with the Company. " (JJB 1, p. 28)

b. " [T]he price charged to the Company by its affiliate, Western Energy Company, is established by competitive bid or negotiation at a price not exceeding the market price for coal delivered under similar conditions." (JJB 1, p. 28)

c. "Negotiation of the terms of a new coal contract for fuel sold by Western Energy to the Company's Coretle Plant in Billings is in process at the time this proceeding is filed. The price term of the new contract was established by competitive bid and is included in the Electric Utility Cost of Service in this proceeding. " (JJB 1, p. 28) The competitive bid process was conducted by Arthur D. Little Company, an independent consultant.

d. "The contract under which coal is sold to Colstrip Units #1 and #2 by Western Energy remains the same as that which was before the Commission in both Docket Nos. 6348 and 6454." (JJB 1, pp. 28-29)

e. The price paid by the MPC for coal delivered to Colstrip Units #1 and 4$2 by the Western Energy Company is lower than that paid under the competitive bid of Western Energy for the Corette Plant fuel supplies. (JJB 1, pp. 28-29)

In support of his conclusion, Wilson offers the following support:

a. "Transactions between a parent and its subsidiary cannot be construed as 'competitive' market transactions. Montana Power buys all of its coal for the Corette and Colstrip plants from its wholly owned subsidiary, Western Energy. Montana Power accounts for about 15 percent of Western Energy's sales. " (Exh. H, p. 29)

b. "Western Energy's coal supply contracts with Montana Power include generous price adjustment provisions to cover cost changes as well as profit escalations. The profit escalation provisions provide for profit increases in excess of cost increases in relation to increases in the Consumer Price Index. " (Exh. H, p 29)

c. "Western Energy also benefits from the fact that Montana Power's plants were apparently located with access to the Company's coal supplies in mind. " (Exh. H, p. 30)

d. The Commission "should exercise particular diligence to assure utility ratepayers that overcharges and profit excesses are not concealed in the prices which the Company pays its own subsidiary for coal and which, in turn, are passed on through to its ratepayers in the form of electric prices. " (Exh. H, p. 30) Quoting a U. S. Department of Justice report: "'The vertical integration bv utilities into coal may provide them an opportunity to evade rate-of-return regulation and thus to capture monopoly profits in their upstream coal operations.'" (Exh. H, p. 31)

e. Other regulatory commissions, in Wyoming, Iowa, Idaho, North Carolina and the Securities and Exchange Commission, have adopted the rate of return method. (Exh. H, pp. 34-36)

f. ". . .Western Energy's profits have indeed been extraordinary in recent years and the coal revenues have been substantially in excess of costs plus a fair return. Moreover, despite very high profits on coal in 1979, Montana Power has, in this rate case, proformed its test year coal expense to include an additional 18 cents of profit on each ton at Corette and an additional profit of 14 cents per ton at Colstrip. " (Exh. H, p. 39)

g. "Arguments supporting high profits on these interaffiliate transactions on grounds that no one else is offering to deliver coal cheaper ignore the fact that the Company's electric plant and coal mine developments are related and that this, in turn, provides the coal affiliate with clear advantages that would not be enjoyed by competitive market rivals. Clearly, competitive arm's length transactions between Montana Power and its own subsidiary, Western Energy, are not sufficient to protect Montana ratepayers from electric rates which include excessive coal profits. " (Exh. H, p. 39)

h. ". . . [C]oal industry equity profits have averaged about 16 percent in this decade. With the exception of very high earnings rates in the three years immediately following the OPEC embargo, in November of 1973, average earnings rates in the coal industry have been under 12 percent. In contrast, Montana Power's Western Energy subsidiary has experienced profit rates in excess of 20 percent on equity capital in every year since 1974," with a more than 25 percent return on equity at year-end 1979. Profits were at the 40 percent level in 1975 and 1976. (Exh. H, p.40)

Based on this evidence, Wilson recommended an adjustment of $610,779 against electric utility revenue requirements "to assure that utility ratepayers are not overcharged and that Montana Power is not permitted to unduly enrich itself at their expense through its subsidiary coal operations." (Exh. H, p. 41) Wilson also recommended disallowance of "the additional pro forma test-year" addition to coal profits of $285,000, for a total adjustment of $900,730. Wilson's adjustment allows for a 13.50 percent return on Western Energy's sales to its parent.
The Department of Justice report "Competition in the Coal Industry, " cited by Wilson, summarizes the problem with the transfer price method:

In practice, however, because of the nature of the coal markets, identification of the appropriate competitive prices is virtually impossible. Coal prices are not some broad national aggregate tut are tied to very specific location and quality factors. In addition, a significant portion of the steam coal is sold by long-term contract. Thus it may prove difficult to estimate an appropriate set of market prices to use to check a utility's accounting price of coal. (Tr. 47, 48) (Emphasis added)

The Company's evidence on the issue fails to address this difficulty. By Burke's testimony the Company asks the Commission to accept its contracted price with Western Energy merely on the basis that, for the Corette plant contract, other companies submitted bids which were higher, according to the Little study. It should be further noted that Burke, although testifying to the conclusions of that study did not participate in it, and the Commission does not have before it the analysis which led to those conclusions. (A report summarizing that analysis was rejected at the hearing as being untimely offered).

The Little study is the basis not only for the Company's claim that the price of coal for the Corette plant is reasonable, but also that the price of coal for Colstrip plants #1 and #2 is reasonable, since that price is below the price of coal for the Corette plant. (Burke-Rebuttal-6) The Company also claims that the price should be found reasonable because it is the same price accepted by the Commission in previous dockets. (JJB 1, p. 29) The Commission cannot accept these arguments. The first argument suffers from the infirmaties discussed by the Justice Report. Whatever the price, the evidence before the Commission does not indicate that costs of extracting and delivering the coal are. Thus, even though the Colstrip #1 and #2 coal price may be lower than that for coal delivered to the Corette plant, Western Energy could still be extracting excess profits from the Colstrip sales, as is in fact indicated by its profit figures. The Company's reliance on the prices offered by other companies for the Corette plant coal supply contract necessarily assumes 1) that those companies, in their operational characteristics are similar to Western Energy, and 2) that those companies' prices are themselves reasonable. The Company failed to offer evidence to support either assumption.

As for the second argument, the Commission in previous dockets had no testimony challenging the Company's coal expenses, and, therefore, had no evidentiary basis for questioning them. The issue of a utility's expenses may always be an issue in a rate case if any party chooses to make them such. This right cannot be "given away" by the Commission and parties in previous cases.

The Company's position ignores the Commission's duty to assure that a utility does not circumvent rate regulation through its transactions with subsidiaries. For example, the Commission has no evidence before it which indicates whether Western Energy was able to submit the lowest bid for the Corette contract because of advantages inherent in the parent/subsidiary relationship which would dampen or eliminate effective competition, such as location of a plant or the engineering of a plant to utilize Western Energy coal more cheaply than coal available from other companies.

In order to address some of the problems raised by the transfer price method of monitoring prices paid by a utility to its wholly owned coal subsidiary, it is reasonable as an alternative, to compare the profits of the subsidiary with those of other coal companies. The evidence in this case shows that in the period 1974 through 1979 a selected number of coal companies averaged 19.91 percent return on their investment; during that same period, Western Energy earned 28.67 percent return on common equity, almost 9 percent more than the other companies. In the test year 1979, earnings for comparable companies averaged 13.1 percent, while Western Energy was earning 27 percent. (Exh. H, J.W. 3) The only rebuttal to this evidence came in the Company's initial brief, where it was argued: "By definition, earnings above 'average' earnings in an industry are not necessarily 'excessive.' The only conclusion that can logically be drawn is that they are only above average." (p. 16)

The Commission cannot dismiss a 9 to 13.9 percent disparity between Western Energy and comparable coal companies as being merely "above average. " At very least, in the absence of rebutting evidence that the companies used for comparison differed in some very important respect from Western Energy, that disparity is a very strong indication that the Company's ratepayers would pay excessive prices for coal supplied by Western Energy if the Company's proposal were accepted. In view of the disparity in profits between Western Energy and other coal companies, it is evident that the transfer price method of monitoring prices paid by the Company to Western Energy does not adequately protect ratepayers from paying excessive amounts for coal used in the utility's production of electricity. The only other method available from the record in this case is Wilson's rate of return approach.

The Company argues that adoption of the rate-of-return method constitutes this Commission's improperly extending its jurisdiction to the regulation of Western Energy's operations. This argument is without merit. Adoption of the rate of return method simply disallows a portion of the Company s claimed coal expenses for rate making purposes. In no way are Western Energy's profits lessened by this action, nor are the contract terms between the Company and Western Energy affected.

By use of this method, the Commission is merely exercising its statutorily mandated obligation to assure that ratepayers reimburse the Company only for expenses reasonably necessary to provide adequate service. The Commission is bound by law to investigate all phases of the Company's operations, including the price it must pay for fuel used to generate electricity.

The Company also argues that, even if the Commission were to adopt a rate of return method for coal purchased from Western Energy, the recommended 13.5 percent return is inadequate "because it assumes . . .that returns in the relatively risky coal industry would be the same as those authorized for public utilities." (JJB 3, p. 6) Despite this argument, however, the Company offered no substitute for what the return figure should be, and offered no evidence on just how risky the coal industry is. The Company made no claim that Western Energy's profit levels in past years were the appropriate guide in calculating a return to reflect the claimed risk. In view of the fact that 13.5 percent is more than the ten year average of profits for coal companies selected by Wilson if the aberrational years following the OPEC embargo are eliminated, and is very close to earnings of other coal companies during the test year, the Commission finds the 13.5 percent figure to be reasonable.

(D) The adjustment sponsored by MCC witness George Hess to the Interest Capitalized Account is common in principle to both electric and gas cost of service. The Commission accepts this adjustment for the reasons stated in the section Capitalized Interest.

(E) The adjustment to Amortization of Excess Balance represents one-half of the excess accumulated deferred income taxes that have been accrued at tax rates higher than the current 46 percent tax rate. $1,383,000 was determined to be the amount accumulated in excess of 46 percent, and the Commission has accepted an amortization period of two years. The amount of the adjustment made to electric cost of service to amortize the excess balance is $692,000. The Commission accepts this adjustment for the reasons stated in the section on Amortization of Excess Balance .

(F) The Federal Income Tax account is adjusted to reflect the increase in federal income taxes resulting from the adjustments to revenues and expenses which have been accepted by the Commission. Included in the accepted adjustment is $251,000 related to the adjustment to Purchase Power expense which the Commission accepted. Also included in the adjustment is a decrease in federal income taxes of $211,000 relating to the pro forma interest expense calculation. Refer to the section Pro Forma Interest Expense for a discussion of this calculation.

(G) The Montana Corporate License Tax account is adjusted to reflect the increase in state corporate taxes resulting from the adjustments to revenues and expenses which have been accepted by the Commission. Included in the accepted adjustment is an increase of $39,000 related to the Purchase Power expense which the Commission accepted. Also included in the adjustment is a decrease in state corporate taxes of $33,000 relating to the pro forma interest expense calculation. Refer to the section Pro Forma Interest Expense for a discussion of this calculation.

(H) This adjustment reflects an attempt to attain complete tax normalization. The Commission defers this adjustment for the reasons set forth in the section on Tax Normalization.

(I) The Applicant used new depreciation rates in this case based on a study made by Gilbert and Associates. The depreciation rate for distribution poles reflected a negative 50 percent salvage (Tr. . pp. 460-464)

Under cross-examination the Applicant was unable to state whether the total retirements on the distribution poles reflected piecemeal retirements or wholesale retirements. (Tr. p. 463) This is a significant factor when determining what the actual costs the Applicant will be experiencing for pole replacements, as the costs incurred on piecemeal replacements are significantly higher than on wholesale replacement of the poles on a nonenergized line. MCC contends that the 50 percent negative salvage reflects piecemeal replacements and it is not likely to be the salvage with wholesale replacement of distribution poles. (Tr. p. 673) An issue similar to this one was raised in Docket No. 6618, with a negative 70 percent salvage proposed by the Applicant in its gas operations. (MCC Brief, p. 10) The Commission accepts the adjustment to depreciation expense sponsored by MCC. The Applicant could not state whether the total retirements on the distribution poles reflected piecemeal or wholesale retirements, and it is not likely that the negative 50 percent salvage would be experienced with wholesale retirements. The accepted adjustment decreases depreciation expense by $213,000. (Tr. p. 674)

Revenues & Expenses

Gas Utility

The following income and expense proposals were submitted. The final column contains the revenue and expense amounts approved by the Commission:

9/30/79 TEST YEAR

(000)

	Applicant's Revenues & Expenses	Consumer Counsel Adjustments	Consumer Counsel Revenues & Expenses	Approved Revenues & Expenses
Operating Revenues	$147,528	$	$147,528	$147,528
Operating Expenses:				
Production Operation (Excl Royalties)	2,266			2,266
Production Operation-Royalties	7,124			2,086
Production-Maintenance	821			821
Products Extraction-Operation	23			23
Production Extraction-Maintenance	4			4
Exploration and Development	5,281			11,275
Other Gas Supply	123,968			115,823
Purchase Re: Bird Plant	436			436
Purchase Re: Trans Canada Sale	10,666			10,666
Purchase Re: Northern Nat. Sale	16,782			16,782
Sub Total Other Gas Supply	$151,852			$143,707
Revenue Reclassified				
Re: Bird Plant	(457)			(457)
Re: Trans Canada Sale	(10,666)			(10,666)
Re: Northern Nat. Sale	(16,847)			(16,847)
Total Other Gas Supply	123,882			115,737

	Applicant's Revenues & Expenses	Consumer Counsel Adjustments	Consumer Counsel Revenues & Expenses	Approved Revenues & Expenses
Storage-Operation	207			207
Storage-Maintenance	54			54
Transmission-Operation	567			567

Transmission-Maintenance	447			447
Distribution-Operation	1,898			1,898
Distribution-Maintenance	791			791
Customer Accounts Expense	1,699			1,699
Customer Service and Info. Expense	400			400
Sales Expenses	103			103
Admin. and General Expenses	5,825			5,825
Labor Adjustment	1,109			1,109
Clearing Accounts Adjustment	76			76
Automotive Expense Adjustment	50			50
Total Operational Maintenance Expenses	$152,627		$152,627	$145,438
Depreciation	5,779		5,779	5,779
Amortization of Common Utility Plant	45		45	45
Amortization of Invest. Tax Cr-Cr	(74)		(74)	(74)
Prov. For Def. Inc. Tax-Lib. Depr.	1,107		1,107	1,107
Prov. for Def. Inc. Tax Amort. of Certain Purchased Nat. Gas Prop.	434		434	434
Prov. for Def. Inc. Tax-Corp. Lic. Tax	586		586	(215)
Prov. for Def. Inc. Tax-Int. Cap.	78	(78)(A)	--	--
Amort. Excess Federal Tax Balance		(27)(B)	(27)	(67)
Taxes Other than Income Taxes	4,448	(236)(C)	4,212	4,212
Income Taxes-Federal	(12,832)	(54)(D)	(12,886)	(8,895)
Income Taxes-Corp. License Tax	(2,227)	(8)(E)	(2,235)	(897)
Current Tax on Deferred Income		(509)(F)	(509)	--
Sub Total	(2,656)		(3,568)	1,429
Total Expenses	149,971	(912)	149,059	146,867

	Applicant's Revenues & Expenses	Consumer Counsel Adjustments	Consumer Counsel Revenues & Expenses	Approved Revenues & Expenses
Utility Operating Income	(2,443)		(1,531)	661
Amort. of Profit on Debt Reacquired at Discount	2		2	2
BALANCE FOR RETURN	(2,441)		(1,529)	663
Natural Gas Utility Rate Base	142,910	268	143,178	142,943
Rate of Return Earned	(1.71%)		(1.07%)	.46%

(A) The adjustment to deferred taxes - capitalized interest was proposed by MCC. The amount of the adjustment made to capitalized interest is $78,000. For the reasons noted in the section Capitalized Interest the Commission accepts this adjustment.

(B) The adjustment to Amortization of Excess Balance represents one-half of the excess accumulated deferred income taxes that have been accrued at tax rates higher than the current 46 percent tax rate. $133,000 was determined to be the amount accumulated in excess of 46 percent, and the Commission accepts an amortization period of two years. The amount of the adjustment made to gas cost of service to amortize the excess balance is $67,000. The Commission accepts this adjustment for the reasons stated in the section Amortization of Excess Balance.

(C) As a result of the revised Montana production presented by Mr. Percival, a new estimate of the net proceeds tax was made by Mr. Hess. The adjustment is not contested by the Applicant and is acceptable to the Commission. The effect of the net proceeds tax adjustment accepted by the Commission is a decrease in taxes other than income taxes of ($236,000), an increase in State Taxes of $16,000, and an increase in Federal Taxes of $101,000.

(D) The other adjustment to Federal Taxes presented by MCC related to the pro forma interest calculation. The Commission accepts a decrease in Federal Taxes in the amount of ($131,000) for the reasons stated in the section Pro Forma Interest.

(E) An adjustment to State Taxes as a result of the pro forma interest in the amount of ($21,000) is accepted by the Commission. This decrease in State Taxes is approved for the reasons stated in the section Pro Forma Interest .

(F) The adjustment reflected the reduction of current taxes on the deferred tax reserve. The purpose of the adjustment was to attain complete tax normalization. For the reasons set forth in the section Full Normalization, this adjustment is deferred by the Commission.

Gas Supply

65. MPC witness Don Percival has proposed the following sources of gas supply to meet its market demands:

	Proposed in Original Prefiled Testimony		Proposed in Supplemental Testimony	
	MMCF	$000	MMCF	$000
Canadian Gas				
Alberta & Southern (A&S)				
Montana Market	12,884	$ 58,776	14,555	$ 66,403
Special Sales	13,097	35,507	11,426	27,884
Sub Total A&S	25,981	94,293	25,981	94,293

Aden				
Purchase	3,046	12,104	3,046	12,104
Royalty	7,107	20,956	7,107	20,956
Fee	534	1,091	534	1,091
Company Use	(801)	C	(801)	--
Net Aden	9,886	34,151	9,886	34,151
Net Aden				
Montana Gas				
Purchase	16,372	38,023	15,087	36,403
Royalty	7,281	729	6,709	671
Company Use	(2,365)	--	(2,179)	--
Net Montana	21,288	38,752	19,617	37,074
Total Supply	57,155	167,186	55,484	165,518
Off-line Sales				
Northern Natural		(24,503)		(16,848)
Bird Plant		(457)		(457)
TransCanada				
Subtotal Special Sales		(6,663)		(6,684)
Net Gas Cost to Mt. Market		$124,897		$130,863

Loss of Market

66. MPC filed supplemental testimony in June, 1980 to reflect the loss of contract or "off line" sales volumes of 1.671 billion cubic feet (Bcf) annually to Northern Natural Gas Company.

67. The Commission finds the partial loss of Northern Natural Gas I sales volumes to be a known and measurable change and accepts it.

68. By way of comparison it can be seen that this loss of approximately 3 percent of total market demand has the effect of raising the cost of gas to the Montana market approximately $6,000,000. The reason for the increase is that the Montana market is charged for a higher proportion of high-cost Canadian gas: The impact of the decrease in sales to Northern Natural Gas Company is a reduction in total supply cost. However, the loss of revenue credits from the Northern Natural Gas sale increases the net cost to the Montana market. The reason for the increase in net gas cost to the Montana market is that the Montana Market is charged for a higher proportion of high cost Canadian gas. The only alternative to changing the A&S (Canadian) supply source as stated above is to reduce the Carway (A&S) volume and incur take or pay. (Percival Prefiled Supplemental pp. 2-3)

69. The loss of market threatens to be irritated further by significant reductions in sales to the Anaconda Company.

70. The Commission also notes a decline in residential sales volumes from 151, 100 cubic feet per customer during 1977 normalized to 137,600 cubic feet during 1979 normalized. (Percival Direct p. 4) This reduction amounts to a 9 percent drop in average residential customer use, a significant reduction in a period of just two years. This reduction, however, also raises the net cost of gas to the Montana market because of the resulting higher proportion of high cost Canadian gas in the gas mix.

71. The Commission applauds the conservation effort so clearly demonstrated in this proceeding but finds it paradoxical that lower usage promotes higher prices. This is contrary to free market supply and demand economics -- the situation regulation attempts to emulate in a monopoly · marketplace.

72. The paradox is caused by MPC's inability to choose its cheapest sources of gas to supply its market. This occurs because the A&S or Carway source of gas contains "take or pay" provisions obligating MPC to pay for gas it does not take if it purchases less than the contractual minimum quantities. Further aggravation is caused by the direct relationship between Carway gas and the steadily increasing price of oil.

Carway Volumes

73. The following schedule shows by year Carway contract volumes (Column 1), maximum available volumes (Column 2), minimum volumes to be taken to avoid paying for gas not taken (Column 3) and potential recovery of take or pay deficiencies (Column 4):

Year Ended	1 (Bcf)	2 (Bcf)	3 (Bcf)	4 (Bcf)
Present to 10/31/85	29.2	32.12	26.28	5.84
10/31/86	27.4	30.14	24.66	5.48
10/31/87	18.25	20.075	16.425	3.65
10/31/88	18.25	20.075	16.425	3.65
10/31/89	14.5	16.06	13.14	2.92
10/31/90	14.6	16.06	13.14	2.92
10/31/91	7.3	8.03	6.57	1.46
10/31/92	7.3	8.03	6.57	1.46
10/31/93	4.2	4.62	3.78	.84

(Exhibit PSC A, Docket 6720)

74. The payment MPC must make if it takes less than Column 3 volumes is the Alberta border price (currently $1.93) minus A&S's cost of service (approximately 204). This payment is made only to the extent A&S incurs take or pay deficiencies. (A&S incurred a deficiency of 44 Bcf during 1979. Tr. p. 221, Docket 6720.) Makeup of deficiencies may occur over the contract life up to yearly potential recovery levels (Column 4).
Price at the time of makeup is the then current border price less amounts paid when deficiencies were incurred. (T.. pp. 130-132, Docket 6720)

75. One method of reducing current Carway purchases involves deferring volumes to future years. It is apparent from Column 4 that the potential recovery of take or pay deficiencies between 11/1/85 and 10/31/93 is 22.38 Bcf. Less Carway gas could be taken between the present and 1985 (the period of high contract volumes) and the resulting take or pay deficiencies made up between 1986 and 1993 (the period of declining contract volumes). This may be an expensive short-term solution, however.

76. MPC has a 7 Bcf take-or-pay deficiency and has made a payment of $8,760,370 (Canadian) to A&S for gas not taken. This deficiency was incurred during the contract year ending June 30, 1978:
The biggest reason we went into take or pay for the contract year ending June '78 was simply rates. The rates weren't enough to justify the higher cost of Canadian gas, and we were operating on a save the ship mode and reduced the take of our expensive gas incurred by take or pay and furnished our less expensive sources harder, just to keep the company alive. (Tr. p. 141, Docket 6720)
Clearly a management decision, this action may cost ratepayers a minimum of the difference between the price when the deficiency was incurred ($2.16) and the current border price ($4.47) or $16,170,000. This amount will increase if the border price increases. Other associated expenses include return on the $8.7 million payment included in rate base and loss of low cost MPC owned reserves used to replace Canadian volumes during 1977-1978.

77. The Commission finds that incurring additional take or pay deficiencies with regard to Carway volumes is an expensive, short-term solution. A longer term approach dictates that minimum contract quantities be taken at the lowest possible price, i.e. the current price, and an alternative, reliable source of supply be secured for future demands -- a supply which is responsive to market conditions.
78. In the interim the Commission strongly encourages MPC management to be vigilant in its attempts to set aside or reduce annual take or pay requirements on Carway purchases so that free market supply and demand conditions prevail.

79 . Managements of other companies with annual take or pay obligations have aggressively sought solutions to this problem. TransCanada Pipelines Ltd., a Canadian pipeline company, initiated action with serious implications for Canada's natural gas industry. It informed its suppliers that it wants to rewrite contracts to cut its minimum gas purchase obligations 20 percent over the next two years.
In a letter to its gas suppliers, TransCanada said that the take-or-pay provisions in its purchase contracts "neither anticipated nor were designed to accommodate periods of prolonged and extensive oversupply such as has existed for the past four contract years and which will continue for at least the next two contract years."
TransCanada said that the "depth and duration of the current North American recession coupled with the impact of energy conservation are restricting near term market growth in resisting domestic and export market areas. Export pricing problems and improvements in domestic supplies available to TransCanada's U. S. customers are further compounding the situation. " (Letter incorporated by reference to transcript, pp. 143,282-283, Docket 6720)

80. The Commission finds these arguments persuasive and encourages MPC to adopt them when it initiates and persues action regarding its annual take or pay obligation to A&S. Further, the Commission requests that MPC keep it informed of any developments regarding this situation.

81. Carway gas purchases are also subject to minimum daily and monthly purchase obligations. (Tr. p. 138, Docket 6720) These obligations force MPC to store gas each year during periods of low demand -- which becomes part of rate base.

82. MPC has not adhered to these contractual terms because there are no associated penalties:

Q Could you tell us what the minimums are for CNP? Daily and monthly?

A MR. MADISON: I think the minimum is 75%, the monthly is 80%, and the annual is 90%. I should add that we have breached that minimum monthly and minimum daily provision in the last two or three years. We have not taken those minimums. We have not taken those monthlies, but the payment is based on the annual obligation, the 90% annual obligation.

Q What sanction are you subject to for not taking daily or monthly minimums?

A I don't know. We discussed that with Alberta and Southern and they are aware that we have not done it, and they are aware of why we have not done it. The contract is a little vague on what the penalties are if you don't meet the minimum monthly and daily, but of course it's very clear on the annual, and we did make the payment for the annual.

Q But you have suffered no monetary or other sanctions?

A That's correct, not to date. (Tr. p. 138, Docket 6720)

83. Accordingly, the Commission finds that MPC should use Carway sources as peaking gas to the greatest possible extent to avoid storing this high cost gas in the rate base.

Other Gas Supply Sources

84. MPC's other sources of gas supply, i . e. Montana company owned or royalty gas, Montana gas purchased from others and Canadian gas not subject to take or pay provisions (Aden!, shall be addressed in this order according to economic dispatch. Utilization levels of each source will be cognizant of the long-term security of supply.

Montana Royalty Gas

85. Montana royalty gas was used by MPC in designing its gas mix to satisfy the market after all other gas sources were "optimized" or as the swing source: "The remaining quantity required to meet our projected market is taken from Company-owned Montana royalty gas. " (Percival Direct, pp. 9-10)

86. Company owned gas is by far the cheapest source of gas available to MPC ratepayers. Rational economic dispatch would dictate that this gas be used first to satisfy market demands.

87. A wise usage level to assure the long-term security of company owned gas should be based on reserve levels . (Tr. pp. 175-176, Docket 6720)

88. MPC owns 88 Bcf of Montana gas reserves. (Tr. p. 122, Docket 6720)

89. President McElwain stated that "a company should feel comfortable with having a so-called reserve life index of somewhere between 12 and 16 years." (Tr. p. 256, Docket 6720) The Commission finds this index to be liberal compared to the ten year reserve life index of the United States. (Tr. p. 191 Docket 6720)

90. Using McElwain's index as a guide, however, the Commission finds that 7.333 Bcf (88) 12) of Montana royalty gas should be used to meet the Montana market.

91. The Commission also finds MPC's proposed 10 percent company use and loss amount to be acceptable for this source of supply.

92. Mr. McElwain stated that the 12-16 reserve life index is contingent upon exploration and development:

Q. So you are assuring that the Montana system has a secure supply of gas for 12-16 years in your letter?

A. I think we have the capability to foresee that will be available, given the proper governmental circumstances involved and some future risk of success in future development and exploration in the State of Montana. (Tr. pp. 256-257, Docket 6720)

93. As recently as November, 1979 the Commission was assured that MPC was engaged in a "relatively high level of exploration" for gas:

Q. Have you evolved something like a long-term plan to shift to the lower cost sources as those opportunities arise? Are you creating opportunities, to compound the question?

A. We are attempting to -- we are carrying on a relatively high level of exploration. We arc in the process now and I believe I mentioned it in previous testimony, but we are into a study to determine what our chances and our probabilities are of being able to get significantly increased Montana source gas by some exploration level greater than we are now conducting. Again with the NGPA our prices of purchased gas in Montana in com petition with others, I feel in the future will be very close to NGPA ceilings. Now, those are somewhat lower than Canadian current border prices, but they are still much higher than our company-owned gas that was found by past exploration. So, we are making a study right now to see what level of exploration we would have to embark on given some input and assumptions of certain success to try to replace a significant portion of our future gas requirements from an exploration program. (Tr. pp. 41-42, Docket 6704-Canadian border price increase to $2.80. Commissioner Turman Cross Examining Mr. Percival)

94. Along the same lines, Mr. Percival, in testimony given in Docket No. 6720, stated "it is highly probable that an exploration effort can be economically justified and will result in a lower cost of gas to the consumer." (Tr. p. 197, Docket 6720)

95. MPC's exploration program, however, has been suspended. (Tr. p. 153, Docket 6720)

96. The Commission approved approximately $4 million dollars of exploration and development (E&D) expense in Order No. 4521, Docket No. 6618 during June, 1979; the company has applied for approximately 5.3 million in this proceeding.

97. The Commission has historically been very receptive to requests by MPC for approval of E&D funds:

Q. Yesterday, I believe Mr. Percival, you stated, in response to a question from Commissioner Schneider, that Montana Power has never been turned down in a request for money for exploration and development. Did I hear you correctly?

A. That is correct. (Tr. p. 195, Docket 6720)

98. The suspension of the E&D program by MPC's management arises not from lack of Commission approval for E&D funds, but rather from a concern that an adequate return is not being earned on capitalized E&D amounts:

Our concern is with the capitalized dollars, where we could go out on a much larger program, be successful, and capitalize X million dollars each year for the next number of future years that we aren't earning an adequate return on those dollars, and business sense says that you don't make that kind of investment if you can't make some kind of return on those investments, so we are hesitant to come in with a large exploration program, looking at our recent past history. (Tr. pp. 195-196, Docket 6720)

99. The Commission notes that MPC accepted the Commission's last approved rate of return on gas rate base as a final determination. This provided MPC the opportunity to earn the fair and reasonable rate of return approved.

100. The Commission has, in this order, approved a fair and reasonable rate of return on the rate base, including the capitalized portion of E&D expenditures. Accordingly, the Commission will not be receptive to suspension of any future E&D program for the reason that an inadequate return is being earned.

101. Mr. Percival's direct testimony includes an E&D scenario to "get a feel from the Commission as to what they think our role in exploration ought to be." (Tr. p. 177, Docket 6720)

102. The scenario is that "400 million dollars in 1980 dollars is needed over the next 20 years to find 400 Bcf of gas which would provide a Montana market at 40 Bcf a year, with 50% company-produced gas starting in 1988." This example "assumes reasonable costs and a scenario that might be workable." (Tr. pp. 169-170, Docket 6720)

103. The Commission finds that company owned gas has historically been the cheapest gas available to MPC ratepayers. It also finds that the need to find a replacement for high cost sources dependent on unrealistic take or pay provisions is vitally important. It therefore shares Mr. Percival's goal that the Montana market be supplied by the largest percentage of company owned gas possible.

104. The Commission finds in this proceeding that the Applicant he allowed $10 million in E&D expenses to be used in non-Canadian ventures.
This amount balances the Commission's commitment to supplying MPC's market
with low-cost company owned gas and current ratepayer impact. According to Mr. Percival's scenario, this amount should provide the Montana market with 10 Bcf of company owned gas by 1989, given the success rate of prior MPC exploration.

105. The Commission finds that MPC should on a quarterly basis provide a report to the Commission detailing its E&D activities.

Montana Purchased Gas

106. MPC used Montana purchased gas at the minimum volume needed to avoid take or pay obligations in designing its prefiled gas mix. (Percival Direct p. 9)

107. Since this is currently the second cheapest source of supply on MPC's system, economic dispatch would dictate maximum volumes of Montana purchased gas be taken.

108. Another factor emphasizing the need to take maximum volumes is the monthly escalation in price of this source. The Natural Gas Policy Act of 1978 provides that much of this gas will be subject to monthly escalations (plus inflation) leading to deregulation. Current escalation rates approximate 34/month. (Tr. p. 168, Docket 6720)

109. Montana purchased gas is slated to be deregulated in 1985; the price at that time may be comparable to alternative fuels such as crude oil and Canadian gas: I don't have a crystal ball, but if they were to de-regulate U. S. domestic natural gas in 1985, as planned, I don't think that domestic natural gas will sell for anv less, and I would suggest maybe even more dollars, than Canadian gas, whatever the level is at that time. " (Tr. p. 156, Docket 6720)

110. Yet another benefit of purchasing maximum volumes is that it stimulates exploration:

Q. Wouldn't the purchase of gas from Montana producers in itself stimulate the exploration and development of Montana gas?

A. It already has.

Q. And if the purchase and investment were even greater wouldn't the stimulation be greater?

A. In a degree, I suspect that's a correct statement. (Tr. p. 116, Docket 6720)

111. Montana Power has 140 Bcf of purchased gas reserves. (Tr. p. 122, Docket 5720)

112. The maximum purchase volume available to MPC is 21.25 Bcf year or 125 percent of the daily contract quantity of 17 Bcf . (Tr. p . 166, Docket 6720)

113. Purchase of Montana gas at this level will use the reserves in 6.6 years (140) 21.25). This compares with a reserve life of 8.55 years (140) 16.372) implicit in MPC's original filing.

114. The Commission finds maximum purchases of this source to be prudent because increased exploration will result, because of monthly escalations in price and because of deregulation in 1985.

115. The 6.6 year reserve life implies that this source will be available after deregulation. If the price at that time is comparable to Canadian sources, the choice between the two sources will be political rather than economic. Mr. Percival clearly stated that he believes Canadian gas will be available to replace Montana purchased gas if deregulation occurs and exploration hasn't maintained Montana reserves:

> I suspect on the next round we could get five times as much from Canada as we did the last time, if we were able to show a need for it. They have trillions of feet of surplus and they would like to sell it, so that's a summary of that. (Tr. p. 157, Docket 6720)

116. MPC has recently adopted a new purchase acquisition policy which may not stimulate maintenance

of Montana reserves because the producer is required to invest in facilities to connect his gas to MPC's system rather than further exploration:

> Our current policy is, or the current direction that I have been given is that we should buy gas delivered wherever possible, either to the gathering line or to the transmission line. The reason for that is so that we do not make any investment unless we absolutely have to. Our policy direction is that we minimize investment, capital dollars, wherever possible, and that is a major shift, I would say in the policy direction in gas acquisition since the response was given. (Tr. p. 109,Docket 6720)

117. Again MPC management is alluding to rate of return deficiency on capital investment. The Commission has expressed its view on this subject in Findings 99 and 100.

118. The Commission finds that MPC's new acquisition policy requires less compressor fuel and results in lower losses of gas, and consequently determines that the company use and loss percetage should be adjusted downward to 5 percent for Montana purchased gas.

Aden Gas

119. MPC used Aden gas at the maximum export permit quantity of approximately 10 Bcf/year in designing its prefiled gas mix. (Percival Direct, p. 9)

120. The Commission finds this source to be the most expensive non Carway source on the system and consequently finds that it should be used as the "swing" or marginal source of supply. As Mr. Madison says: "Its not that much of d bargain for the consumer anymore." (Tr. p. 175, Docket 6720)

121. MPC owns approximately 200 Bcf of reserves at Aden. A reserve life of 68 years results from usage levels found appropriate in this order.

122. The Commission is very concerned that Aden reserves be available in future years due to the prospect of U.S. deregulation in 1985 as discussed above and in light of MPC's new Montana purchase gas acquisition policy also discussed above.

123. Because of this the Commission finds E&D (mostly development) applied for appropriate as it pertains to the Aden properties. Using ratepayer money to develop leases that would otherwise be lost, gives them a right to the gas in the future and adds to security of supply:

> Q Has CNG continued to both explore for and develop gas at Aden?
>
> A Not much exploratory. It's a mature property that has been worked on since about 1951. We have drilled hundreds of holes. We initially bought, and don't quote these numbers, but something like 300 Bcf, and we have almost that much, and it has been drilled up quite a bit. We do continue to drill some development wells, because the new Canadian government land regulations essentially

say you have to drill all of your leases in the next two or three years or lose the leases, so where we have had to drill to keep from losing leases we deem to be productive, we drilled those wells in order not to lose that asset, and we continue to do so, but it's more of a development situation than exploration in that old area, because it has been very highly drilled. (Tr. pp. 163-164, Docket 6720, Ms. Shore Cross-examining Mr. Percival)

124. The Commission is also aware that export permits for Aden gas start declining in 1985 and terminate after 1987. It encourages MPC to approach Canadian governmental authorities to allow future export of volumes not exported under existing permits due to reduced current usage of this high priced source.

125. Aden gas historically has been a mixture of purchased gas and company own d gas. The mixture has maintained the same ratio as relative reserves of both sources. The company proposed a 70 percent produced 30 percent purchased ratio in this proceeding.

126. In redirect Mr. Percival admitted that the 70-30 ratio is no longer valid:

Q With respect to the Aden reserves, would you briefly outline the recent reserve addition history with respect to the Company and other producers in the area?

A Yes, it would be partly in a better response to Commissioner Schneider's question about the 70-30. What has happened over time is that we have added reserves to our reserves inventory at a much fatter rate than out side producers have added to their reserve inventory : and while over the years we have used that 70-30, that increase in our reserve is relative to theirs, has created a different percentage, which we should perhaps be adjusting in future discussions and exhibits. (Tr. p.441, Docket 80.4.2)

127. The Commission finds a ratio of 80 percent produced 20 percent purchased gas to be acceptable.

Effects of Changing Market on Mix

128. The Commission assumes a declining market will persist because of the impending loss of approximately 3.5 Bcf of sales .o Anaconda Company.

129. In the event of a decline in market, the Commission suggests the following:

a. Aden sources should be reduced first to a minimum of 2 Bcf plus company use and loss or 2.162 Bcf. This level is considered the minimum at which all wells may be proportionately reduced; thus avoiding drainage problems associated with selectively shutting-in wells.

b. Montana purchased gas sources with associated take-or-pay obligations should then be reduced to minimum levels at which take-or-pay deficiencies are avoided.

c. Remaining Montana purchased gas should then be adjusted to the lowest levels possible without violating contract terms.

d. Montana royalty gas should then be reduced.

130. The Commission finds the following gas volumes and associated costs:

	Mmcf	$000
Canadian Gas		

A&S:		
Montana Market	14,525	66,422
Special Sales	11,455	27,887
Subtotal A&S	25,980	94,309
Aden	559	1,884
Purchase	2,235	5,897
Royalty	147	299
Company Use	(221)	
Net Aden	2,720	8,080
Montana Gas		
Purchase	21,250	49,300
Company Use	(1,066)	
Royalty	7,333	734
Company Use	(733)	
Net Montana	26,788	50,034
Total Supply	55,488	152,423
Off-line Sales		
Northern Natural		(16,848)
Bird Plant		(457)
TransCanada		(10,666)
Subtotal Special Sales		(27,971)
Storage		(6,771)
Net Gas Cost to Montana Market		117,681

PART E
REVENUE REQUIREMENT
Electric Utility

131. The Commission finds that the additional annual revenue required in the Applicant's electric operations is $22,754,000 as follows:

(000)

Rate Base	$442,706	
Recommended Rate of Return	10.342%	
Recommended Return		$45,785
Balance for Return		34,335
Return Deficiency		$11,450
	% of Revenue	
Revenue Deficiency	100.00	$22,754
Operating Revenue Deductions		
MCC Tax @ .07%	.07	16
State Taxable Income	99.930	22,738
State Tax @ 6.75%	6.745	1,535
Federal Taxable Income	93.185	21,203
Federal Income Tax @ 46%	42.865	9,753
Net Operating Income	50.320	$11,450

Gas Utility

132. The Commission finds that the additional annual revenue required in the Applicant's gas operations is $28,627,000 as follows:

(000)

Rate Base	$142,943	
Recommended Rate of Return	10.541%	
Recommended Return		$15,068
Balance for Return		663
Return Deficiency		$14,405
	% of Revenue	
Revenue Deficiency	100.00	$28,627
Operating Revenue Deductions		
MCC Tax @ .07%	.07	20
State Taxable Income	99.930	28,607
State Tax @ 6.75%	6.745	1,931
Federal Taxable Income	93.185	26,676
Federal Income Tax @ 46%	42.865	12,271
Net Operating Income		$14,405

PART F
Electric Rate Structure

133. All matters pertaining to electric rate design, which determines the relative increase applicable to each customer and customer class, will come before the Commission at a hearing on June 30, 1981. Until such time as rate design matters are completed in the Phase II hearing, the increase in rates will be allocated to the classes on a uniform percentage basis .

Cost of Service and Rate Design-Natural Gas

134. The Commission heard and reviewed testimony and evidence pertaining to three cost of service and rate design issues:
(1) the appropriate costing and pricing methodology;

(2) the allegations of discrimination and cross-subsidization, presented by Great Falls Gas Co., and other gas utilities, respecting rates which they pay to Montana Power as a result of Commission Order No. 4521b in Docket No. 6618; and

(3) the proper allocation of gas storage costs on the Montana Power , Company system.

These issues will be discussed consecutively. These discussions will be followed by a determination of the appropriate rate for each class of customers .

<u>Costing and Pricing Methodologies</u>

135. This Commission recognized the need for rate reform in Order No. 4521b in which it was decided that "it is time to totally restructure the rates to reflect not the past but current and future conditions -- to abandon the piecemeal adjustment to an inappropriate cost of service methodology. " (p. 15, paragraph 31)

136. Nevertheless, in Docket No. 80.4.2 we find testimony in support of two conceptually distinct pricing methodologies. Montana Consumer Counsel's witness Dr. J. W. Wilson and Dr. Thomas Power, witness on behalf of District XI Human Resources Council and Montana's Power to the People, Inc., have advocated a pricing philosophy based on marginal costs. Great Falls Gas Company, Treasure State Pipeline Co. and Shelby Gas Association, Intervenors in the case, have generally argued for a more traditional average-embedded costing approach. The Applicant, while not specifically opposing a marginal cost based methodology, presented, through the testimony of Mr. Matthews of Economic and Engineering Services, Inc., an average-embedded cost of service study. During cross-examination Mr. Matthews went on to advocate use of the Atlantic-Seaboard 50/50 allocation method. (Tr. p. 567) Applicant's witness Mr. Matthews of EES also testified to the issue of marginal cost pricing and provided an opinion as to the appropriate timing consideration:

. . . it is a correct goal of regulation to develop price schemes which promote allocation efficiency, and secondly, employment of marginal cost theory is the basis for achieving that.

Marginal cost theory is quite clear that the correct pricing scheme is short-run marginal cost as opposed to other definitions of marginal cost which can include long-run marginal cost and something called long-run incremental cost. (Tr. p. 564)

137. Great Falls Gas Company, arguing for and from the same position as the other resale utility intervenors in this matter, did not specifically challenge the recoupment of costs on a volumetric basis. However, Great Falls Gas Company contends the volumetric allocation of costs does not comport with causal responsibility. Mr. Geske addresses the issue in his prefiled testimony:

While the order requires that costs be recovered on a volumetric basis, I do not believe that the Commission intended that all costs must be so allocated. Proper cost allocation procedures must be followed if rates are to be kept in line with costs. In the present case, improper allocation of customer costs to interruptible customers away from firm customers results in rates for firm customers on the Montana Power system that are artificially low. (Testimony, p. 5)

138. Mr. Geske argues that volumetric pricing does not lead to volumetric costing and that such a departure from traditional cost of servicing techniques, to the extent that they ignore traditional causal responsibility allocative methods, leads to cross-subsidication and/or discrimination. Mr. Chick advocated a traditional embedded cost rationale for the allocation of customer and distribution costs.

139. The fundamental reason for abandoning the traditional historical cost approach in favor of moving to marginal cost pricing is due to the changing relative scarcities of pipeline (or capacity) and commodity.

140. Dr. Wilson recognizes the changing relationship between capacity and scarcity when he writes:

In the past, regulatory commissions have concentrated their interests on total revenue requirements and have left rate structure determination largely at the discretion of the regulated utility companies. And, until recently, in most jurisdictions gas utility rates were typically structured in declining blocks and revenue requirements were allocated between classes so that large users paid a lower average unit price per MCF than small users.

During the 1950's and 1960's when gas prices at the wellhead were stable or falling, increased purchases at the distribution level often also translated into reduced average purchase gas costs per unit of gas sold. Given today's more limited gas supplies and much higher incremental gas supply costs, however, these conditions obviously no longer hold. It is now far more appropriate to adopt largely volumetric rate structures for natural gas service. (Exh. H, pp. 48-49)

Dr. Wilson concludes that:

Gas utility rates should reflect economic costs. System costs should be allocated on the basis of what it actually costs to provide service to particular consumers at particular times. The marginal cost of gas supply should be a particularly important consideration in this regard. (Exh. H, pp. 43-44)

141. Dr. Wilson went on to state that, while he believed Applicant's rate design proposal generally comported with the volumetric methodology, he would also recommend four modifications. These included: 1) recoupment of the winter discount to Montana Power Company's firm class from within that class; 2) no allocation of the costs of Montana Power Company's distribution system to the resale utility class; 3) allocation of storage costs to the interruptible class; and 4) elimination of the 25 percent Montana Power employee discount. (Exh. H, pp. 51-55)

142. No marginal cost study was presented by either Applicant or Intervenors in this Docket. In that regard it becomes difficult to determine the appropriate marginal cost figure from which to begin a marginal cost approach .

143. Dr. Wilson, during cross-examination, pegged the marginal cost of natural gas on the Montana Power system at $4.47, but offered no indication of whether he considered that figure to be a short-run or long-run marginal cost value. (Tr. p. 734)

144. Dr. Power similarly rejected the use of traditional embedded cost allocations which do not reflect current supply, demand, and price realities:

. . . accounting costs look at the cost of past discoveries and the sunk costs of past pipeline investments. In that sense these embedded costs reflect a cost situation currently faced by the utility.

Natural gas used to be a . . . surplus commodity the production of which was almost costless. The major cost of turning it into a useful fuel was transmitting and distributing it. In that setting a rational rate structure would attempt to ration pipeline capacity but encourage gas commodity consumption. The resource situation in the 1970's reversed itself. Natural gas itself is now a scarce commodity and because of shortages and declines in demand pipelines have excess capacity. It is now necessary to ration the commodity itself not the pipeline. The rate structure called for today is quite different from that of the past. (Direct, pp. 2-3)

145. Dr. Power then established his basic cost of service and rate design recommendation:

Rates should be designed to reflect as well as possible the long run incremental costs of gas. Such an approach would indicate that commodity costs are now and will continue to be the dominant cost considerations. The primary costs MPC will be incurring to provide gas to customers are commodity oriented costs: exploration and development of new sources of supply. These new sources of supply will be significantly more costly than older sources. All customers should be informed of this through their rates. Thus I support continued commitment on the part of this Commission to marginal costs analysis and volumetric pricing. (Direct, p. 10)

146. Dr. Power distinguishes short-run from long-run marginal cost and suggests it is the latter that is most appropriate for rate-making purposes:

As I have tried to indicate in my testimony, I tend to use a long run incremental cost definition of marginal cost. I have also in my testimony indicated that one probably could come up with an infinite number of different measures of marginal costs. I want to include the fact that according to the testimony of Montana Power Company and according to the acts of some of the other utilities within the state, Arctic gas and coal gasification are being given serious consideration, as well as fairly extensive exploration outside of the state of Montana.

Therefore, I would use some near term estimate of what the cost of those supplemental sources of gas are going to be. The estimates that we have been offered range as high as $10.00 per MCF. (Tr. pp. 773-774)

147. Although the price at the wellhead for Montana gas is currently below the marginal cost of gas on the Montana Power Company system, it is clear that as a result of the deregulation policies of the Natural Gas Policy Act that these prices will continue to escalate in the future. Anaconda Company's witness Gordon P. Hercod, in Docket No. 6720, which has been incorporated as part of this docket, presented evidence indicating the extent of this escalation in the future. Exhibit GPH-3 provides Atlantic Richfield Corporation's projection of natural gas prices through the year 1994. By the mid-1980's the projected price is in the $6.00 to $7.00/Mcf range with the price near $12.00/Mcf in 1994.

COMMISSION ANALYSIS AND RATE DESIGN FINDINGS

148. The Commission finds that the traditional Seaboard allocation method, advocated by Mr. Matthews in this record, simply does not reflect the realities of natural gas supply, demand and price on the Montana Power Company system. This basic finding was emphatically contained in Order No. 4521b, Docket 6618. The record evidence in this case reinforces that determination.

149. Based upon the expert testimony of Drs. Wilson and Power, the Commission continues to find that a marginal cost pricing method for natural gas constitutes the most appropriate pricing policy for the Montana Power Company system. To the extent that the commodity (natural gas) has become relatively scarce and increasingly expensive as compared to transmission and distribution facilities, pricing the commodity at the margin provides the consumer with a price which more nearly reflects the costs to society of gas consumption. Establishing a rate design to reflect the dramatically increasing commodity cost is particularly important when energy conservation and resource efficiency are fundamental concerns.

150. The Commission recognizes that implementation of full marginal cost pricing is not practicable given the range of plausible marginal cost values and the revenue requirement constraint.

151. None of the witnesses performed a comprehensive marginal cost analysis. The focus of Drs. Wilson and Power was appropriately upon the marginal commodity cost for natural gas, which is clearly the dominant cost for the system. To the extent marginal facility costs were not examined, the marginal costs which they suggest are conservative. The Commission finds that in the short run the marginal commodity cost of gas on the MPC system is at Ieast $4.47 per Mcf, the current Canadian border price. It is further apparent that in the intermediate to long-run the marginal commodity cost may approach the $10-12 per Mcf range. (See Findings 146 and 147). The marginal cost of gas has been rising for several years. There is nothing on this record to suggest that this trend will not continue. The Commission finds it prudent and responsible to focus upon this long-term perspective in establishing rate design policy.
152. To the extent marginal costs exceed average system costs, the rate design selected must be modifies to meet the revenue requirement determined in this order. The Commission finds that use of the volumetric cost allocation methodology advocated by Drs. Wilson and Power is the most appropriate technique on this record to meld the marginal cost approach to the revenue constraint. Volumetric rates more nearly reflect marginal commodity costs than the other techniques recommended in this case. The volumetric costing and pricing method, thereby, promotes an efficient market response to the long-term gas shortage and escalating commodity cost.

153. The Commission finds that the resale utility class should be allocated no customer and distribution costs from the MPC system. It is, therefore, readily apparent that the rate tn the utility class will be substantially below the marginal cost of supply on the MPC system as approximated by the volumetric costing and pricing method. The resulting rate to the utility class is also about 394 per Mcf lower than to any other customer class on the MPC system. (Power Rebuttal Exhibits) However, this accommodation fairly recognizes that the ultimate customers will be faced with the full customer and distribution costs of the local utility.

154. The Commission adopted an inverted rate structure or seasonal lifeline in Docket No. 6618, Order No. 4521b for the firm customer class.
Formulation of the inverted rate was based upon a 25 percent discount on the first 15 Mcf per month of gas used by each firm customer during the period December through March. The revenue shortfall was recouped entirely from within the firm class by increasing the rates on all remaining gas used during the year. Consequently, the resulting tailblock more nearly approximated the marginal gas cost.
155. The Commission finds that the evidence and testimony of Dr. Power on this record supports continuation of this basic inverted rate structure.

156. The Commission finds that the seasonal inverted rate should continue to apply only within the existing firm customer class. The record does not adequately support expanding this seasonal lifeline provision to the interruptible industrial class.

The character of interruptible service contracts, the differing delivery pressure, the large relative volumes used, and a lower priority in the event of catastrophic cu, "ailment continue to provide a reasonable basis for a separate classification.

Furthermore, by continuing to exclude the interruptible industrial class from the seasonal lifeline provision no additional rate disparity between MPC customers and those of other utilities is introduced. The concerns expressed by Dr. Wilson on this issue are thereby eliminated in a straightforward manner. The "need" to impute identical but artificial customer mixes for all utilities, as Dr. Wilson has recommended, is avoided.

157. The Great Falls Gas Company, along with Treasure State Pipeline Company, Consumers Gas, Shelby Gas Association and the U. S. Department of Defense, has provided testimony arguing that the rate design promulgated in Order No. 4521b results in discriminatory rates to the resale utilities. They note that prior to Order No. 4521b the wholesale rates to resale utilities were lower than retail rates to Montana Power firm class customers but that after Order No. 4521b the situation had reversed. Mr. Geske addresses the issue in his prefiled testimony:

Q. What effect did Order 4521b have on rates for gas volumes sold on the Montana Power system?

A. The effect was to decrease the rate to MPC residential - customers and increase the rate to Great Falls Gas residential customers. (Direct, p. 2)

And continuing later:

Prior to Order 4521b Great Falls Gas residential customers were paying less than the rate Montana Power Company residential customers were paying as shown on Exhibit (LG No. 2). Exhibit LG (LG No. 3) contains bill comparisons after 4521b was implemented, with rates placed in effect on December 10, 1979. The exhibit shows that the Great Falls Gas Company average residential bill went from 8.24 percent below Montana Power Company before 4521b to 19.8 percent above Montana Power Company after Order 4521b rates were implemented. (Direct, p. 31

158. Mr. C. Eugene Chick of Stone and Webster, Inc., witness on behalf of Great Falls Gas, explains the reason for the rate disparity and offers a solution to alleviate the disparity. He argues that while Applicant's witness Matthews provides a cost of service study based on traditional allocative techniques, the study is not used to allocate costs but, instead, costs are allocated on a volumetric basis in accordance with Applicant's interpretation of Order No. 4521b. The result is that 21 large interruptible customers are paying 40 percent of Montana Power Company's customer costs (Chick Direct, p. 5; Tr. p. 560) and are also paying 40 percent of the distribution costs, even though 86 percent of the interruptible load is not attached to the distribution system but is direct transmission line sales (Tr. Matthews, p. 562). This volumetric allocation substantially reduces rates to the MPC firm customer class, producing the price disparity noted by Mr. Geske.

159. To alleviate the problem, Mr. Chick suggests that customer costs be allocated on the basis of a weighted number of customers (Exhibit (CEC-2), Testimony) reducing revenue responsibility for the interruptible class from $3,708,673 to $57,781. The balance would be allocated to the MPC firm class.

160. Carrying the subsidization/discrimination issue a step further, Consumer Council witness Dr. J. W.

Wilson provided testimony in support of spreading the revenue shortfall accruing to the seasonal discount on the Montana Power system to all Mcf's of gas by MPC sold during the year. During cross-examination Dr. Wilson explained his point of view:

> I still think that there is a cross-subsidization problem that exists, particularly with respect to some of the resale customers, not to the extent that I portrayed on JW-5, but to an extent. And I would say that that relates in part to the way in which the discounted volumes, the revenues that are necessary to cover the cost of the discounted volumes, are treated in the Company's filing as opposed to the way they are treated in the adjustment, and in the presentation that I have made. If you follow the arithmetic behind my computation, what you will see is that I am taking a concept of a 25% winter discount and spreading that 25% winter discount evenly among all volumes of gas throughout the system. The way in which the Company's filing handles the winter discount, I think in my opinion, is discriminatory to some of the smaller gas utilities which have a larger percentage of their total sales eligible for the discount.
>
> So we get into a small utility with a large percentage of its total sales qualifying for the winter discount and we require the winter discount subsidy to come from only the remaining customers on that small utility system, rather than being spread evenly among all of the gas supplies that are ultimately supplied by Montana Power, you will find that the customers on the small gas distribution system are receiving less benefits and not being treated on the same basis with respect to the discount as the retail customers on the Montana Power system where the spreading of the discount is taking place over a larger volume of gas and a small percentage of the total is eligible for the discount. (Tr. pp. 722-724)

However, Dr. Wilson observes that the discrimination is not a class issue but an issue of one system (Montana Power Company) versus another (the other gas distribution utilities). (Tr. p. 724) In his prefiled testimony he presents a method for recouping the Great Falls Gas Company winter discount revenue shortfall (Exh. H, pp. 53-54, and Exhibit _ (JW-5) and JW-6).) He estimates the benefit to Great Falls Gas customers to be approximately 54/Mcf. (Tr. p. 727) Interestingly, Great Falls Gas Company argues in its brief that the solution proposed by Wilson accentuates the discrimination.

161. Dr. Power addressed the discrimination charge raises by Great Falls Gas in his rebuttal testimony. He points out that "Mr. Chick's adjustments do nothing to significantly change the costs allocated to GFG. The primary focus of Mr. Chicks allocation is MPC's firm and interruptible customers, not GFG. " (Rebuttal Testimony, p. 2' While recognizing Mr. Geske's concern with the fact that GFG's residential rates are now higher than MPC's residential rates instead of being lower as they were in the past, Dr. Power nevertheless recognizes that:

> This result, however, as Mr. Chick's adjustments point out, is not due to any discrimination against GFG. It is the result of GFG having a different mix of customers. In particular, it is the result of GFG having no large interruptible customers on its system. As a result the "customer costs" per MCF of gas sold to ultimate customers are higher on GFG's system than on MPC's system. (Rebuttal, p. 3)
>
> * * *
>
> Thus the cause of the "problem" is not that costs were unfairly allocated to GFG but that GFG has a different type of mix of customers which are more expensive on average to service than MPC's ultimate customers. GFG may wish this were not the case but it is and neither this Commission nor

Order No. 4521b are responsible for this objective difference. (Rebuttal, p. 4)

* * *

There is no significant discrimination against GFG because its allocation of costs is based upon the same volumetric logic as the allocation of costs among other customers. The relatively rate its customers face, as pointed out above, is unrelated to the costs allocated to GFG. It s related to MPC's firm retail customers receiving a relative benefit from the raisin the interruptible customer rates toward incremental commodity costs. (emphasis added(Rebuttal, pp. 5-6)

162. Dr. Power continues to discuss how the economic logic of marginal cost pricing can provide guidelines for resolving the issue of subsidization:

The economic costs a customer imposes on the system are the additional costs incurred because of that customer's behavior, that is, the marginal costs or incremental costs. If individuals are not charged more than those additional costs their behavior causes, they cannot be said to be subsidizing anyone for they are not even covering fully the costs associated with their own behavior. If they are not subsidizing anyone, of course, no other customer can be receiving a subsidy from them.

Thus if a customer's rates do not cover the marginal costs associated with his behavior, we know he is not subsidizing anyone. (Rebuttal, p. 6)

163. Dr. Power categorically refuted the basic subsidization issues raised by Dr. Wilson's direct testimony:

Q. Dr. John W. Wilson, in his prefiled testimony, suggests that MPC's proposed rates "require that [other] utilities' retail customers subsidize the Montana Power Company's retail customers" (p. 51, lines 21 and 22) and "ultimate customers of the other utilities . . . will pay not only for their own distribution systems, but will also make a contribution to the distribution costs of serving Montana Power's own ultimate customers, " (p. 54, lines 6-10). Do MPC's proposed rates discriminate against GFG in this way?

A. No. As I understand MPC's "calculation of proposed rates", it was careful to allocate customer and distribution costs only to MPC ultimate customers. In addition, the revenues lost because of the winter discount were collected only from MPC's firm non-utility customer class, the class which most benefits from the winter discounts.
Thus neither type of cross-subsidization which Dr. Wilson mentions takes place in MPC's proposed cost allocation. (Power Rebuttal, p. 10)

164. Dr. Power provides a comprehensive discussion of the subsidization issue from the perspective of establishing an appropriate costing and pricing method:

Rate should be designed to reflect as well as possible the long run incremental costs of gas. Such an approach would indicate that commodity costs are now and will continue to be the dominant cost considerations. The primary costs MPC will be incurring to provide gas to customers are commodity oriented costs: exploration and development of new sources of supply. These new sources of supply will be significantly more costly than older sources. All customers should be informed of this through their rates. Thus I support continued commitment on the part of this Commission to marginal costs analysis and volumetric pricing.

The increment cost approach suggests that until a customer's rates approach the incremental cost of gas, t}.e allocation of costs among customer classes is an issue of secondary importance. Thus collection of "customer" costs or "distribution" costs on a volumetric basis can be justified on a cost basis in that it moves all customers' rates towards incremental commodity costs. Since these are real economic costs actually imposed upon the system, there is nothing irrational or necessarily unfair about such an allocation.

The traditional embedded average cost approach would suggest the by collecting "customer" costs or "distribution" costs from customers who receive no services from those facilities and whose consumption did not create the need for those facilities is irrational and unfair. But this conclusion is the result of the point from which the embedded cost approach begins its analysis and the definition of "causal cost responsibility" chosen. It sets out to assign average historical accounting costs to customers and establish cost responsibility on this basis. Economic theory argues for beginning the analysis, not with this cost concept but with the additional costs a person's behavior imposes on the system or saves the system. It consciously and deliberately ignores the very costs which the embedded cost analysis suggests are being irrationally allocated, the costs associated with the existing distribution system and customer service. It does so because most of these costs cannot be avoided or saved. In that sense they are not economic costs and individuals are not causally responsible for them. Thus although in an accounting sense the industrial interruptible customers are paying for the distribution system serving residential customers, in an economic sense they are paying nothing more (in fact substantially less) than the incremental commodity costs they in fact impose upon the system. Thus all suggestion of cross subsidization vanishes and the approach this Commission took in its previous order takes on a cost logic of its own. The EES cost analysis which suggests that there is no cost logic at all to the existing rate structure is purely a result of the definitions and formulae they chose to apply. (Direct, pp. 10-11)

Commission Findings: Cross-subsidization/Discrimination

165. The Commission finds that the cost of service and rate design findings contained earlier in this order squarely face and fairly resolve the issue of cross-subsidy raised by Great Falls Gas Company and others. The testimony of Dr. Power, a witness for Montana's owner to the People (a low income and senior citizen group based in Great Falls), provides a comprehensive examination of the cross-subsidy issue from the proper perspective -that of the appropriate cost of service and rate design for natural gas service from MPC. The Commission adopts Findings 161 through 164 as its own on the issue of cross-subsidy.

166. Viewed from the perspective of the appropriate cost of service and rate design, the allegations of cross-subsidy and discrimination are without foundation. The Great Falls Gas Company and other utilities are paying no customer or distribution costs for the MPC system. This accommodation is specifically designed to assure that the ultimate customers of these distribution utilities pay only the local system costs. (See Finding 153)
Similarly, the concern expressed by Dr. Wilson, that inclusion of the interruptible class in the lifeline provision would introduce an artificial disparity between the rates of MPC customers and the customers of the distribution utilities, was resolved. (See Finding 156) The cost allocations and rate design adopted by the Commission simply provide that the distribution utilities share on an equal basis with all other customers of MPC in the costs associated with natural gas service from MPC.

167. The "solution" proposed by Great Falls Gas Company results in virtually no change in the costs allocated to the distribution utilities. It is, therefore, readily apparent and conceded that these distribution utilities are not subsidizing the retail customers of Montana Power. Obviously, then, Great Falls Gas Company contends that the Commission must, by whatever means, establish a rate to the distribution utilities which will allow them to charge their retail customers rates that are equal or closely comparable to those of MPC's retail customers.

168. To the contrary, the Commission finds logic and merit in the argument that, ceteris paribus, customer costs on the Great Falls Gas System per Mcf of gas consumed are higher than on the Montana Power

Company system. This observation simply reflects the fact that one system (MPC) has a number of large volume users whereas the other system (GFG) does not. That rates should in turn reflect this fact does not connote discrimination, but only makes manifest the realities of the situation. Absent a "mathematical integration" of the distribution utilities into the MPC system, a differential rate among the customers of the various utilities is virtually assured because of local system characteristics and costs. Such differential rates are objective and reasonable. Such rate differential constitutes neither cross-subsidy nor unjust discrimination.

Storage Costs

169. A preponderance of evidence concerning storage costs indicates that it is no longer appropriate not to allocate a portion of these costs to the interruptible class. As Consumer Counsel witness Wilson states in his prefiled testimony:

Whereas it might be advocated that interruptible customers not be charged certain costs, such as storage under some conditions, in this case that does not appear to be appropriate. That is, it is highly unlikely that curtailments will occur or that there will be significant interruptions to industrial customers during the period these rates are in effect. Indeed, the Company has indicated in Data Response 91 to the Office of Consumer Counsel, that no curtailment is forecast for 1980. (Exh. H, pp. 54-55)

And from Mr. Chick:

It is difficult for me to understand why storage costs are not allocable to interruptible customers, in view of the substantial sales to these customers during the winter months when there is a net withdrawal from storage. (Testimony, p. 3)

From Mr. Matthews:

. . . were I to conduct a cost of service study which selects only one allocation scenario, I would chose one which allocates the storage function by the seasonal withdrawals of natural gas from the storage facility. (Tr. p. 559)

And from Dr. Power:

If the interruptible users were not consuming during the I winter months, a smaller storage system would suffice. Their steady consumption during the heating season and preheating season causes the storage recharge period to be longer, reduces storage possibilities in the transmission system itself, and requires a larger storage system. Thus sone of the storage system costs would be legitimately assigned to the interruptible users. (Testimony, · p. 8)

Dr. Power continues to address the proper method of allocating storage costs:

Thus one could try to calculate the part of storage interruptible customers are responsible for. This would be complicated by the fact that considerable gas is stored underground for other than current use. In fact the carrying costs of this stored gas dominates storage costs. Some of this gas is simply additional supply store in, the ground for future use just as other natural gas is being held in place in natural storage for future use by MPC. These are simply supply costs and should be allocated on a volumetric (commodity) basis. (Testi mony, p . 9)

170. Testimony in this Docket establishes that the current gas bubble combined with declining market virtually insure that curtailments or interruptions will not occur during the period in which the rates are effective.

Additionally, the evidence is persuasive that interruptible customer utilize gas from storage before and during the peak usage period. Based upon the evidence of record, the Commission finds that storage costs should be allocated on a volumetric basis in the same fashion as all other gas supply costs.

Employee Discounts

171. Wilson recommends that the employee discount be discontinued. The Commission takes notice of its previous thorough consideration of this matter in a rulemaking proceeding. At that time, the Commission declined to eliminate the discounts because to do so would result in higher costs to ratepayers. Because these discounts are tax exempt benefits, were they discontinued, the company would have to provide additions to salaries, which would be taxable.

The Commission does, however, reiterate its policy that the employee discount should not result in employees paying less than the average commodity cost.

CONCLUSIONS OF LAW

1. Applicant, Montana Power Company is a corporation providing electric and natural gas services within the state of Montana and as such is a "public utility" within the meaning of Section 69-3-101, MCA.

2. I he Montana Public Service Commission properly exercises jurisdiction over the Applicant's operations pursuant to Title 69, Chapter 3, MCA .

3. The rate base adopted herein reflects original cost depreciated values and as such complies with the requirements of Section 69-3-109, MCA, that the value placed upon a utility's property for ratemaking purposes "...may not exceed the original cost of the property."

4. The rate of return allowed meets the constitutional requirement that a public utility's return must be "commensurate with returns on investments in other enterprises having corresponding risks and sufficient to assure confidence in the financial intergrity of the enterprise, so as to maintain its credit and to attract capital. " Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

5. Section 693-201, MCA declares:

> Public utilities to furnish service for reasonable charges.
> Every public utility is required to furnish reasonably p
> adequate service and facilities. The charge made by any
> public utility, for any heat, light, power, water,
> telegraph, or telephone service, produced, transmitted,

delivered, or furnished, or for any service to be
rendered as or in connection with any public utility,
shall be reasonable and just, and every unjust and
unreasonable charge is prohibited and declared unlawful.

It is with this statute in mind that the Commission considers MPC's purchases from its wholly-owned subsidiary, Western Energy. Recognizing that it can go no further than to consider MPC's cost of fuel, the Commission also believes that sole reliance on a transfer price comparison has clear limitations, thus it determines from an examination of Western Energy's profits that MPC is paying excessive prices for coal; therefore the adjustment set out in this order is necessary to assure that the requirements of 69-3-201, MCA are met.

6. The Commission acts in its legislative capacity when it allocates utility costs to the various customer classes.

7. The objectives of conservation, efficiency and equity are promoted by the rate structure approved in this order.

8. The rate structures authorized by the Commission, based upon analysis of the entire record, are just, reasonable, and not unjustly discriminatory.

ORDER

1. The Montana Power Company shall file rate schedules effective for services rendered on and after December 19, 1980, which reflect annual electric utility revenue increases of $22,754,000 and annual gas utility revenue increases of $28,627,000.

2. Rate schedules filed shall comport with all Commission determinations set forth in this order.

3. All motions and objections not ruled upon are denied.

Done and dated this 19th day of December, 1980 by a vote of 5-0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

GORDON E. BOLLINGER, Chairman

CLYDE JARVIS, Commissioner

THOMAS J. SCHNEIDER, Commissioner

JAMES R. SHEA, Commissioner

GEORGE TURMAN, Commissioner

ATTEST:

Madeline L. Cottrill Secretary

(SEAL)

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (3()) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure Act, esp. Sec. 2-4-702, MCA; and Com j mission Rules of Practice and Procedure, esp. 38.2.4806, ARM.